UNITED STATES OF AMERCA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	**)** **)** **)**	**Docket No. ER26-59-000**

Reforms to Energy Uplift Credit Rules

Craig Glazer
Vice President–Federal Government Policy
PJM Interconnection, L.L.C.
1200 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 423-4743
craig.glazer@pjm.com

Ryan J. Collins
Vivian W. Chum
Wright & Talisman, P.C.
1200 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 393-1200
collins@wrightlaw.com
chum@wrightlaw.com

Chenchao Lu
Associate General Counsel
PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403
(610) 666-2255
chenchao.lu@pjm.com

October 7, 2025

TABLE OF CONTENTS

I. BACKGROUND 6

II. PROPOSED TARIFF AND OPERATING AGREEMENT CHANGES 9

A. Reforms to PJM's Real-time Energy Make Whole Credit Rules 10

1. PJM proposes to implement TRLD MWh, which improves PJM's ability to assess how closely to PJM's expectations a resource has performed over an entire commitment period (proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)) 13

a. Overview of status quo metrics 13

b. Proposed TRLD MWh metric to replace status quo metrics used to calculate real-time energy make whole credits and deviation charges 15

i. Calculating TRLD MW 18

ii. Calculating TRLD MWh 20

c. Benefits of proposed reform (examples) 21

i. Example 1: TRLD replaces Dispatch Signal MW as metric used to calculate real-time make whole credits and deviation charges 22

a) Example 1, Status Quo Dispatch Signal MW Metric 23

b) Example 1, Proposed TRLD Metric 25

c) Example 1-Extended, Proposed TRLD Metric 27

ii. Example 2: TRLD Replaces LMP Desired MW as metric used to calculate real-time make whole credits and deviation charges 28

2. PJM proposes a balancing Energy Make Whole credit calculation to support a more transparent and intuitive methodology (proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2)) 32

a. Overview of status quo calculation 32

b. Proposed balancing Energy Make Whole credit calculation 34

i. Step 1 of the proposed balancing Energy Make Whole credit calculation 36

ii. Step 2 of the proposed balancing Energy Make Whole credit calculation 37

iii. Step 3 of the proposed balancing Energy Make Whole credit calculation 40

iv. Inclusion of additional inputs..... 41

c. Benefits of proposed reforms..... 42

3. PJM proposes revisions to the real-time make whole payment eligibility rules to align a resource's eligibility with its PJM commitment period (proposed Tariff, Attachment K-Appendix, section 3.2.3(e))..... 46

a. Overview of status quo eligibility rules..... 46

i. Status quo eligibility start 48

ii. Status quo eligibility end 49

b. Proposed revisions to real-time eligibility rules (proposed Tariff, Attachment K-Appendix, section 3.2.3(e))..... 49

i. Proposed eligibility start 50

ii. Proposed eligibility end 52

c. Benefits of proposed reforms..... 52

4. Taken together, the proposed reforms improve alignment between real-time energy make whole credits and whether a resource has operated as PJM expected across the resource's commitment period..... 55

B. Conforming Changes to Generation Resource Deviations (proposed Tariff, Attachment K-Appendix, section 3.2.3(o)) 58

1. Overview of status quo rules governing deviations..... 58

2. Proposed, conforming revisions to replace Desired MW metrics with TRLD MWh metric when measuring deviations and to remove certain exemptions from deviations (proposed Tariff, Attachment K-Appendix, section 3.2.3(o)) 60

C. Other Conforming or Clarifying Revisions 64

1. Impact of proposed reforms on resources that have limited their flexibility through restricted offer parameters (proposed Tariff, Attachment K-Appendix, sections 3.2.3(e-1), 3.2.3(e-2), 3.2.3(o)) 65

a. Resources using Fixed Gen Flag: TRLD MWh metric to calculating real-time make whole credits 66

b. Resources using Fixed Gen Flag: DA MWh or TRLD MWh metrics to calculate deviation charges..... 67

c. Resources offering limited dispatchable range: TRLD MWh metric to calculate real-time make whole credits 67

d. Resources offering limited dispatchable range: TRLD MWh metric to calculate deviation charges 68

2. Violations of Parameter Limits (proposed Tariff, Attachment K-Appendix, Section 3.2.3(e)(iii)) 68

3. Impact of Market Suspensions on real-time make whole credits and deviation charges (proposed Tariff, Attachment K-Appendix, sections 3.2.3(e-2)(iii), 3.2.3(g), 3.2.3(q)(iii)) 70

4. Reactive Services Make-Whole credits (proposed Tariff, Attachment K-Appendix, sections 3.2.3B(f), 3.2.3B(j))..... 70

5. Flexible Resources self-scheduled in real-time Energy Market (proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2)(i))..... 71

6. Revisions to defined terms and non-substantive changes..... 72

III. STAKEHOLDER CONSULTATION..... 72

IV. EFFECTIVE DATE..... 73

V. CORRESPONDENCE..... 74

VI. DOCUMENTS ENCLOSED 74

VII. SERVICE 75

VIII. CONCLUSION 76

wright& talisman

1200 G Street, N.W., Suite 600
Washington, D.C. 20005-3898
Phone: 202.393.1200
Fax: 202.393.1240
wrightlaw.com

October 7, 2025

The Honorable Debbie-Anne A. Reese
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E., Room 1A
Washington, D.C. 20426

Re: *PJM Interconnection, L.L.C.*, Docket No. ER26-___-000
Reforms to Energy Uplift Credit Rules

Dear Ms. Reese:

Pursuant to section 205 of the Federal Power Act ("FPA"),[1] PJM Interconnection, L.L.C. ("PJM") proposes reforms to PJM's Open Access Transmission Tariff ("Tariff") and Amended and Restated Operating Agreement of PJM ("Operating Agreement") pertaining to PJM's balancing Operating Reserve credits—a type of uplift that is also commonly referred to as real-time energy make whole credits or payments.[2] The proposed package of reforms—the product of a collaborative effort with the Independent Market Monitor for PJM ("Market Monitor")—will improve the alignment between the level of real-time energy make whole credits paid to a generation resource and how closely to PJM's expectations a resource is operating across the consecutive Real-time Settlement Intervals of that resource's commitment period. The package of reforms also includes proposed conforming changes and/or clarifications to PJM's real-time generation resource deviation rules and other related market settlements rules.

[1] 16 U.S.C. § 824d.

[2] Terms not otherwise defined herein shall have the same meaning as set forth in the Tariff and/or Operating Agreement. The Tariff and Operating Agreement are currently located under PJM's "Intra-PJM Tariffs" eTariff title, available here: https://etariff.ferc.gov/TariffBrowser.aspx?tid=1731.

If accepted, the proposed reforms to PJM's Tariff and Operating Agreement[3] will: (1) provide PJM stakeholders with a more complete picture of how closely to PJM's expectations a resource is operating in the Real-time Energy Market[4] across multiple, consecutive five-minute increments of the resource's commitment period based on a new metric—Tracking Ramp Limited Desired megawatt hours ("TRLD MWh")—which will be "used in the calculation of [real-time energy make whole credits] and generator deviation charges as a representation of the level at which the resource would be desired if operating as requested by [PJM]";[5] (2) revise the real-time energy make whole credit equation to be more intuitive and aligned with a resource's performance relative to PJM's expectations, such that the credit calculation more clearly and transparently reflects the financial impacts of following or deviating from PJM's expected outcomes;[6] (3) clarify the rules that determine when a resource is considered eligible for real-time energy make whole payments;[7] (4) implement conforming changes to PJM's real-time generation resource deviation rules to replace Desired MW metrics with TRLD MWh and remove existing exceptions to deviation charges that are no longer necessary in light of the use of TRLD

[3] To the extent PJM Open Access Transmission Tariff, Attachment K-Appendix ("Tariff") and proposed revisions thereto are referenced throughout this transmittal letter, it can be assumed that PJM has proposed identical revisions to parallel sections of Amended and Restated Operating Agreement of PJM, Schedule 1 ("Operating Agreement").

[4] PJM's Market Settlement Reporting System will provide stakeholders with the results of PJM's calculations of real-time energy make whole payments based on the TRLD MWh metric and Actual MWh.

[5] Proposed Open Access Transmission Tariff, Attachment K-Appendix, section 3.2.3(e-1) ("proposed Tariff").

[6] *Id.* section 3.2.3(e-2).

[7] *Id.* section 3.2.3(e)(i).

MWh;[8] and (5) implement conforming and clarifying changes to other related markets settlements rules.[9]

PJM is also submitting non-substantive changes to its Tariff and Operating Agreement, including replacing the term "Operating Reserve," to the extent that it refers to energy make whole payments,[10] with the more widely recognized terms "Energy Make Whole," "energy uplift," or "uplift."[11] Energy Make Whole describes settlement calculations that compensate resources for additional costs incurred in excess of market revenues,[12] while energy uplift refers more broadly to both Energy Make Whole credits and lost opportunity cost credits, which compensate resources for foregone profits. To describe real-time energy make whole credits in PJM's Tariff and Operating Agreement, PJM proposes to replace the term "balancing Operating Reserve credits" with "balancing Energy Make Whole credits."[13] PJM also proposes to replace the term "Operating Reserve charges" with "deviation charges" and to replace the term "Operating Reserve deviations" with "deviations."[14]

The comprehensive package of reforms to the real-time energy make whole rules and accompanying conforming and/or clarifying changes to other rules, including those

[8] Proposed Tariff Attachment K-Appendix, section 3.2.3(o).

[9] *Id.* sections 1.10, 1.10.1A, 1.12, 8.8, 3.2.3, 3.3A, and 3.2.3B; proposed Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., section 18.17 ("proposed Operating Agreement").

[10] PJM's Tariff and Operating Agreement will continue to use the term "Operating Reserve" to the extent that the term refers to the operational reserves that PJM carries to account for operational uncertainty.

[11] Proposed Tariff, Attachment K-Appendix, sections 1.12, 1.10(d), 1.10.1A(f), 3.2.3, 3.3A 8.8; proposed Operating Agreement section 18.17.1(e).

[12] Proposed Tariff, Attachment K-Appendix, sections 1.12, 3.2.3, 3.3A; proposed Operating Agreement section 18.17.

[13] Proposed Tariff, Attachment K-Appendix, sections 1.12, 3.2.3, 3.3A.

[14] *Id.*

governing deviations, are the result of a multi-year collaborative effort by PJM and the Market Monitor, with the overwhelming support of stakeholders.[15] The proposal was developed as a single package of reforms pursuant to an Issue Charge brought jointly by PJM and the Market Monitor and further revised based on stakeholder feedback during 14 special sessions of the Markets Implementation Committee ("MIC").[16] The Markets and Reliability Committee endorsed the package of reforms with a sector-weighted vote of 4.611 in favor (and a threshold 3.335).[17] The Members Committee subsequently endorsed the proposal on August 20, 2025, by acclamation with no abstentions and no objections.[18]

The proposed package of reforms is a just and reasonable improvement to the status quo. Specifically, the proposal supports greater transparency, allowing Market Sellers to better understand the level of energy uplift credits and deviation charges that are assessed to and/or against each resource and provide stronger incentives for generation resources to

[15] *Issue Details: Operating Reserve Clarification for Resources Operating as Requested by PJM*, PJM Interconnection, L.L.C., https://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue=f9b3dbf5-4149-4ea6-9ad3-0c452ff9f386 (last visited Sep. 2, 2025).

[16] *Operating Reserve Clarification for Resources Operating as Requested by PJM*, PJM Interconnection L.L.C., MIC Special Sessions (https://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue=f9b3dbf5-4149-4ea6-9ad3-0c452ff9f386) (In addition to 14 MIC Special Sessions, an MIC special session scheduled for February 2024 was cancelled).

[17] *Markets & Reliability Committee Minutes*, PJM Interconnection, L.L.C., 1 (July 23, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/mc/2025/20250820/20250820-item-09a---mrc-report.pdf.

[18] *Members Committee Minutes*, PJM Interconnection, L.L.C. (Aug. 20, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/mc/2025/20250820/20250820-agenda.pdf. Subsequent to the Markets & Reliability Committee and the Members Committee endorsements of the proposal, PJM has made several minor typographical corrections to the proposed Tariff language. Of note, PJM adds a clarifying sentence at the beginning of the new section 3.2.3(e-1)(i): "Tracking Ramp Limited Desired MW (power) is an adjusted metric that accounts for the impact of Regulation and reserve assignments or manual dispatch instructions." Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(i). In addition, PJM corrects a typographical error in the draft proposed Tariff. The numerator and denominator should be flipped in the following equations, which is in keeping with the status quo rules: Deviation Percentage = Abs[1-TRLD MWh/Actual MWh] should be Deviation Percentage = Abs[1-Actual MWh/TRLD MWh]. Likewise, Day-ahead Deviation Percentage = Abs[1-Day-ahead Scheduled MWh/Actual MWh] should be Deviation Percentage = Abs[1-Actual MWh/Day-ahead Scheduled MWh]. Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(o).

follow PJM's commitment and dispatch instructions. Resources that consistently fail to follow PJM's requests over multiple intervals will not receive real-time make whole payments for megawatts ("MW") not otherwise desired by PJM, and generator deviations from dispatch signals will be better recognized.

Because PJM's uplift rules are inherently complex and implementing reforms to the rules will require numerous and significant software updates, the package of proposed reforms is expected to be implemented towards the beginning of 2027 if this filing is accepted by the Commission. In the meantime, PJM intends to publish TRLD MWh results in PJM's Market Settlement Reporting System for informational purposes only beginning in 2026 should the Commission accept this filing. To be clear, PJM will not use these informational results in any settlement calculations during this transitional period as the results are only intended provide Market Participants with the time and necessary information to familiarize themselves with the new TRLD MWh metric.[19] PJM therefore respectfully requests that the Commission approve the package of reforms, as proposed, with an unspecified effective date of 12/31/9998. Furthermore, so that PJM can know whether to proceed with the necessary software changes to implement the proposed reforms, PJM requests the Commission issue an order by December 8, 2025, 62 days from the date of this filing.[20]

[19] Lisa Morelli, *Balancing Operating Reserve (BOR) Credit Reform: PJM/IMM Proposal Overview*, Members Committee, 6 (Aug. 20, 2025) https://www.pjm.com/-/media/DotCom/committees-groups/committees/mc/2025/20250820/20250820-consent-agenda-b---01-bor-credit-reform---presentation.pdf ("2025 BOR Credit Reform Proposal Overview").

[20] PJM has assigned an effective date of December 8, 2025, to one eTariff record, Tariff, Attachment K-Appendix, section 1 (Market Operations) submitted with this filing (in metadata only) in order to effectuate Commission action by this date.

I. BACKGROUND

Pool-scheduled resources are eligible for make whole payments, which, under the existing rules, are referred to as Operating Reserve credits. The degree to which pool-scheduled resources will be made whole for their energy output is impacted by how well they have followed dispatch. To the extent pool-scheduled resources deviate from PJM's commitment and dispatch instructions, they may also be subject to deviation charges, referred to under the existing rules as Operating Reserve charges.

Resources may receive both Operating Reserve credits and Operating Reserve charges in a single Operating Day, and at the conclusion of each Operating Day, PJM separately accounts for Operating Reserve credits to and Operating Reserve charges against each generation resource.[21] Operating Reserve credits are further separately accounted for in the Day-ahead Energy Market and Real-time Market at the end of each Operating Day.[22]

For purposes of calculating Operating Reserve credits, PJM divides each pool-scheduled resource's commitment period into one or two Segments, which are comprised of blocks of five-minute, Real-time Settlement Intervals.[23] The first Segment is equal to the greater of a resource's day-ahead schedule and the resource's Minimum Run Time.[24] The second Segment, if applicable, is equal to "any block of Real-time Settlement Intervals [in which] the resource operates at PJM's direction in excess of the greater of its day-ahead schedule and [M]inimum [R]un [T]ime.[25] In other words, the second Segment is equal to

[21] Tariff, Attachment K-Appendix, section 3.2.3(e).

[22] *Id.* sections 3.2.3(e) and 3.2.3(b).

[23] *Id.* section 3.2.3(e).

[24] *Id.*

[25] *Id.*

the remainder of the contiguous Real-time Settlement Intervals in an Operating Day when the resource is operating at the direction of PJM.

No Load Costs are evenly distributed across Real-time Settlement Intervals in the first and second Segments. Start-up Costs are evenly distributed across intervals in the first Segment only. Thus, the second Segment does not include Start-up Costs, which should have been fully recovered in the first Segment. Incremental costs can differ depending on the resource's offer price in any given interval in any Segment. In addition, costs and revenues in different Real-time Settlement Intervals in the same Segment can offset one another, however, offsets do not apply across different Segments or across different Operating Days.[26]

PJM evaluates the performance of each pool-scheduled resource in the Real-time Market at the end of each Operating Day. Pool-scheduled generation resources that have operated for at least one five-minute Real-time Settlement Interval may receive real-time energy make whole credits, referred to as balancing Operating Reserve credits, to cover shortfalls between the resource's specific costs incurred as a result of complying with PJM's commitment and dispatch instructions and the amount the resource earns in revenues.[27] Balancing Operating Reserve credits help to ensure that competitive energy and ancillary service market outcomes in the Real-time Energy Market do not require efficient resources to operate for the PJM system at a loss.

[26] However, the proposed TRLD MWh metric does measure a resource's *performance* in accordance with PJM's expectations across the entire period when a unit is expected to be online or dispatchable across Segments or across Operating Days.

[27] Tariff, Attachment K-Appendix, section 3.2.3(e).

A resource experiences loss when gross energy and ancillary services market revenues are less than its short run marginal costs, which include all elements of the resource's energy offer—i.e., Start-up, No Load, and Incremental Offer costs. Real-time energy make whole credits are a primary means of ensuring resources are not economically disadvantaged for following PJM commitment and dispatch instructions in the Real-time Market. These credits are available to resources committed by PJM to run in the Real-time Market in order to provide assurances that resources' operating costs will be covered when they run at PJM's direction, regardless of the prevailing Locational Marginal Price ("LMP"). Thus, real-time energy make whole credits, currently referred to in the Tariff as balancing Operating Reserve credits, compensate resources for following PJM's instructions in the Real-time Energy Market even when doing so would be uneconomic for such resources.

This filing is focused on proposed reforms to the status quo rules governing PJM's balancing Operating Reserve credits. However, PJM is also proposing conforming or clarifying revisions to other market settlements rules, including rules governing how PJM measures deviations for purposes of assessing charges. Resources may be separately assessed Operating Reserve charges at the end of each Operating Day. Operating Reserve charges are penalties that allocate a share of the costs of the balancing Operating Reserve credits paid to other resources to the deviating resource.[28] Operating Reserve charges approximate socialization of the costs to the PJM market arising from resources' deviations from PJM's commitment and dispatch instructions in the Real-time Energy Market.

[28] Tariff, Attachment K-Appendix, section 3.2.3(o).

II. PROPOSED TARIFF AND OPERATING AGREEMENT CHANGES

PJM and the Market Monitor's evaluation of the real-time energy make whole payment rules revealed that, under the current rules, resources that have not followed PJM's commitment and dispatch instructions over multiple Real-time Settlement Intervals may nevertheless receive some real-time energy make whole credits for MW not truly desired by PJM and/or be assessed minimal deviation charges.[29] In other cases, under the current rules, generation resources may not receive sufficient out-of-market payments to make them whole to their costs when they have followed PJM's commitment and dispatch instructions.[30] The proposed reforms in this filing will increase the precision and transparency of the status quo rules, and better align the level of real-time energy make whole credits paid to pool-scheduled resources with PJM's commitment and dispatch instructions across all of the five-minute intervals within resources' commitment periods.[31]

Below, PJM first addresses proposed reforms to PJM's balancing Operating Reserve credit rules. Second, PJM describes proposed, conforming revisions to how deviations are assessed for purposes of calculating deviation charges. Third, PJM describes conforming and/or clarifying revisions that PJM is proposing to other rules.

[29] *See Issue Charge: Operating Reserve Clarification for Resources Operating as Requested by PJM*, PJM Interconnection, L.L.C. (2023), https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2024/20240112-special/operating-reserve-clarification-for-resources-operating-as-requested-by-pjm---issue-charge.pdf ("Issue Charge"); *Problem/Opportunity Statement: Operating Reserve Clarification for Resources Operating as Requested by PJM*, PJM Interconnection, L.L.C. (2022), https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2024/20240112-special/operating-reserve-clarification-for-resources-operating-as-requested-by-pjm---problem-statement.pdf ("Problem/Opportunity Statement").

[30] *See* Issue Charge; *see* Problem/Opportunity Statement.

[31] *See* Issue Charge; *see* Problem/Opportunity Statement.

Attachments A and B to this transmittal letter provide additional support for the proposed package of reforms. Specifically, Attachment A contains a set of tables that serves as a key to the proposed revisions to PJM's Tariff and Operating Agreement. The relevant provisions are presented in Attachment A in the same order in which the provisions are addressed in this transmittal letter.

Attachment B is the affidavit of Senior Director of Market Settlements Ms. Lisa Morelli on behalf of PJM ("Morelli Affidavit"). The Morelli Affidavit: (1) provides technical details behind how the TRLD MWh (energy) metric, and underlying Tracking Ramp Limited Desired MW (power) ("TRLD MW") input, are calculated, as described in proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1); (2) explains, using an example based on a hypothetical resource, how PJM's proposed real-time energy make whole credit equation works in application; and (3) describes how PJM's eligibility rules work in tandem with other proposed revisions to PJM's real-time energy make whole payment rules by relying on a series of examples. Additionally, Exhibit No. Morelli-0001, an example based on a hypothetical resource that applies the proposed balancing Energy Make Whole credit equation, is appended to the Morelli Affidavit.

Clean and redline versions of the proposed Tariff and Operating Agreement revisions are provided in Attachments C and D, respectively.

A. Reforms to PJM's Real-time Energy Make Whole Credit Rules

PJM is proposing clarifications and refinements to PJM's real-time energy make whole credit rules that, if accepted, will improve PJM's ability to recognize whether resources are complying with PJM's directives and credit such resources accordingly. The proposed reforms aim to strengthen incentives for resources to follow PJM's directions by

improving the alignment between the amount of real-time energy make whole credited to resources and PJM's expectations across resources' entire commitment periods. Each of the proposed revisions to the rules support clearer, more transparent, and more accurate assessments of real-time energy uplift.

First, PJM proposes to replace the currently effective Real-time Desired MW ("RT Desired MW") metrics with TRLD MWh, which will be "used in the calculation of [real-time energy make whole credits] and generator deviation charges as a representation of the level at which the resource would be desired if operating as requested by [PJM.]"[32] TRLD MWh is an approximation of what PJM's dispatch signal would have been had the resource followed dispatch over time, across multiple, consecutive five-minute intervals in the Real-time Energy Market, while also considering the resource's ramp rate. Notably, the TRLD MWh metric is not entirely new. A version of this metric was previously adopted by the Commission in a 2024 order accepting PJM's proposed reforms to its Regulation market construct.[33]

TRLD MWh is an improvement over three status quo metrics presently used to determine the energy output to which a resource should be made whole. Two of the status quo metrics are limited to evaluating how well a resource follows PJM's commitment and dispatch instructions in single, five-minute intervals. However, these existing metrics do not account for how closely to PJM's expectations a resource is operating in real-time over consecutive five-minute intervals. The third status quo metric does not account for a

[32] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1).

[33] *PJM Interconnection, L.L.C.*, 187 FERC ¶ 61,173, at P 15 (2024) (proposing reliance on a "resource's tracking ramp rate limited expected output level," to replace a Regulation market construct that "overstate[d] a resource's lost opportunity cost and does not consider the resource's ramp rate, or whether the resource is consistently following the PJM energy dispatch signal").

resource's ramp rate limitations and may therefore expect a resource to perform in a manner that is not physically possible.

Second, PJM proposes to revise the currently effective balancing Operating Reserves credit equation by: (1) limiting the total real-time energy make whole credits that a resource may earn to the amount the resource would have received had it operated in accordance with PJM's expectations throughout the resource's commitment, as measured through TRLD MWh; (2) breaking down the calculation into three steps to create a more transparent and intuitive formula for calculating real-time energy make whole payments and thus removing the apples-to-oranges comparison embedded in the status quo balancing Operating Reserves credit calculation; and (3) more completely recognizing profits a resource receives from the provision of other market services, including revenues paid through opportunity costs.[34] The revisions to the real-time make whole credit calculation addresses scenarios in which the status quo real-time energy make whole credit calculation may give rise to payments of real-time energy make whole that are under- or over-stated based on how closely to PJM's expectations a resource is operating in the Real-time Energy Market across five-minute intervals during the length of a resource's commitment period.

Third, PJM is proposing revised eligibility rules that, if accepted, will better align a resource's real-time energy make whole eligibility period with a resource's full commitment period. Under the proposed eligibility rules, the eligibility period will no longer be restricted to the Real-time Settlement Intervals in which a resource is online or dispatchable. Instead, the eligibility period will generally cover the entire PJM

[34] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2).

commitment period.[35] In most cases, under the revised rules, the number of Real-time Settlement Intervals in which resources will be considered eligible for real-time energy make whole payments will increase.

The revised eligibility rules, when implemented in tandem with the real-time energy make whole calculation and the TRLD MWh metric reforms, will improve PJM's ability to capture all of the costs and revenues in all of the Real-time Settlement Intervals in which a resource is eligible to receive real-time energy make whole credit. The result is a more accurate representation of the costs the resource did not recover and for which it would therefore need to be made whole, which also ensures that the resource is not made whole in excess of what the resource would have been owed if it had operated consistently with PJM's expectations. Thus, the financial consequences of deviating from PJM's real-time commitment and dispatch instructions will be more transparently reflected in each Real-time Settlement Interval in which a resource is deemed eligible to receive make whole payments. The real-time energy make whole credits paid to resources will better align with the resource's performance relative to PJM's commitment and dispatch instructions.

1. PJM proposes to implement TRLD MWh, which improves PJM's ability to assess how closely to PJM's expectations a resource has performed over an entire commitment period (proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)).

a. Overview of status quo metrics

Under the status quo rules, PJM determines whether "a generation resource is following dispatch"[36] by comparing actual output against one of three RT Desired MW

[35] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e)(i).

[36] Tariff, Attachment K-Appendix, section 3.2.3(o).

metrics,[37] which, as described in section II.A.2, below, serve as inputs to PJM's status quo balancing Operating Reserves credit equation. The three types of RT Desired MW metrics currently used in PJM's balancing Operating Reserves credit equation are: Dispatch Signal MW, Ramp Limited Desired MW, and LMP Desired MW.[38] Dispatch Signal MW and Ramp Limited Desired MW reflect the MW that a resource should be producing in a particular Real-time Settlement Interval based on PJM's dispatch instructions.[39]

LMP Desired MW, which is distinct from the other two RT Desired MW metrics, is the intersection of the incremental offer curve and the Real-time LMP. In most cases, PJM relies on LMP Desired MW when a resource is deemed to be not following dispatch by a significant amount (i.e. 20% or more off dispatch) or the resource has limited its flexibility.[40] The three metrics are described in greater detail in PJM's Tariff and PJM Manual 28.[41] Table 1, below, provides a brief summary of the Dispatch Signal MW, Ramp Limited Desired MW, and LMP Desired MW metrics:

[37] Tariff, Attachment K-Appendix, section 3.2.3(o).

[38] *See id.*

[39] *Id.*

[40] *See id.*

[41] *Id.*; *PJM Manual 28: Operating Agreement Accounting*, PJM Interconnection, L.L.C., Sections 5.3.2.2 and 5.3.2.3 (July 23, 2025), https://www.pjm.com/-/media/DotCom/documents/manuals/m28.pdf ("PJM Manual 28").

Table 1. PJM Desired MW Metrics Under Current Tariff Rules[42]

Methodology	Description	When Used as Desired MW
Dispatch Signal	Dispatch Signal calculated by RT SCED (Real-Time Security Constraint Economic Dispatch) and sent to generators.	• Dispatch Signal MW is less than or equal to the ramp-limited desired MW • Dispatch Signal MW is greater than the ramp-limited desired MW and the resource's Real-time MW is greater than the ramp-limited desired MW
Ramp Limited Desired (RLD) *(used most frequently)*	The MW value that the unit should have achieved between Dispatch Signals or RT SCED case approvals.	Generally used when resource is "following dispatch" within +/- 20%
LMP Desired	The LMP Desired is the MW level on the incremental offer curve where the Dispatch Run LMP intersects the offer curve. Not a ramp-limited value.	• Percent off dispatch is greater than 20% or • Resource's Fixed Gen Flag is set in Real-time but not Day-ahead or • Resource clamps its economic limits from Day Ahead to Real-Time

b. Proposed TRLD MWh metric to replace status quo metrics used to calculate real-time energy make whole credits and deviation charges

PJM is proposing Tariff revisions to replace the current reliance on the three existing RT Desired MW metrics in the balancing Operating Reserve credits equation with one metric—TRLD MWh. The proposed TRLD MWh metric approximates a resource's expected output—beginning at the Real-time Settlement Interval when PJM expects the resource to be online or dispatchable, while honoring soak time differences,[43] and ending when the resource goes offline unless exceptions set forth in the proposed Tariff apply, such as when the resource has tripped, was taken offline by the Market Participant, or otherwise failed to follow PJM's instructions.[44]

TRLD MWh measures how well the resource operated in accordance with PJM's expectations of that resource across all of the preceding five-minute Real-time Settlement

[42] Aaron Baizman, *Tracking Ramp Limited Desired Metric*, PJM Interconnection, L.L.C., 3 (Nov. 10, 2023), https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2023/20231110-special/item-05---tracking-ramp-limited-desired-metric.pdf.

[43] Attachment B (Affidavit of Lisa Morelli on Behalf of PJM Interconnection, L.L.C.) ¶ 12 (citing proposed Tariff Attachment K-Appendix, section 3.2.3(e-1)(i)) ("Morelli Aff.").

[44] Morelli Aff. ¶¶ 48-52 ((citing proposed Tariff Attachment K-Appendix, sections 3.2.3(e-1)(iii)).

Intervals in which PJM expected the resource to be online or dispatchable.[45] If PJM expects a resource to be online or dispatchable across multiple Operating Days, PJM continues to calculate TRLD MWh across Operating Days until the appropriate TRLD MWh calculation end time.[46]

The TRLD MWh metric represents a just and reasonable improvement to the status quo metrics. First, as discussed below, the proposed TRLD MWh metric enables PJM to better track RT Desired MW in a Real-time Settlement Interval. TRLD MWh measures a resource's expected performance across consecutive five-minute settlement intervals over the entire period from when PJM expects the resource to be online or dispatchable until the resource goes offline, while also accounting for the resource's ramping capability.[47] The status quo Dispatch Signal MW and Ramp Limited Desired MW metrics, by comparison, only enable PJM to track how well a resource is following dispatch in single, discrete Real-time Settlement Intervals. Thus, the TRLD MWh metric more accurately reflects the MWh that a resource should have been producing in a given Real-time Settlement Interval had it operated, over time, in accordance with PJM's expectations. That is, the TRLD MWh metric is not constrained by a resource's current output. The measurement of how closely

[45] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1) ("The [TRLD] metric is used in the calculation of balancing Energy Make Whole credits and generator deviation charges as a representation of the level at which the resource would be desired if operating as requested by [PJM]. There are two [TRLD] metrics, one measured in MW (power) and the other measured in MWh (energy), each of which are calculated as described below and as further detailed in the PJM Manuals").

[46] Morelli Aff. ¶¶ 78-79 (citing proposed Tariff Attachment K-Appendix, section 3.2.3(e-1)(iii)). Attachment A, Table A.1 provides a key to the relevant provision and proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1).

[47] Morelli Aff. ¶¶ 12, 51 (citing proposed Tariff Attachment K-Appendix, sections 3.2.3(e-1)(i), 3.2.3(e-1)(iii)).

a resource has performed to PJM's expectations is therefore not skewed by a resource's failure to perform as PJM expected in prior Real-time Settlement Intervals.

Second, the TRLD MWh metric allows PJM to establish RT Desired MW values when a resource is not online during its commitment period, regardless of whether or not the resource is offline at the direction of PJM. By contrast, the current Dispatch Signal MW and Ramp Limited Desired MW values, which rely on the resource's actual output at the beginning of each five-minute interval, can only be applied when resources are online.[48] Thus, under the existing rules, if a resource is not online throughout its commitment period (e.g. a resource trips during the day-ahead commitment period), the Dispatch Signal MW and Ramp Limited Desired MW metrics may not always fully account for the costs and revenues that the resource would have incurred had it remained online and produced the desired energy output since they generally result in a RT Desired MW of 0 when the resource is offline.

Third, the TRLD MWh metric is also an improvement to the LMP Desired MW metric because it accounts for the resource's ramp rate and is a more realistic representation of the output a resource can achieve.

Fourth, TRLD MWh "represents the expected energy produced between the start of the Real-time Settlement Interval and the end of the Real-time Settlement Interval."[49] The status quo Real-time Desired MW metrics are power metrics (MW), which represent expected output at a specific point in time. On the other hand, PJM's Real-time Energy Market settles in energy (MWh), which represents the amount of energy produced or used

[48] Morelli Aff. ¶ 158; *see also* Tariff, Attachment K-Appendix, section 3.2.3(o).

[49] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1).

over the duration of a Real-time Settlement Interval. A resource's real-time output is therefore an energy value. The proposed TRLD MWh is an energy metric as well.[50] Comparing the resource's actual real-time energy (MWh) output to a desired energy (MWh) output metric will enhance PJM's ability to measure the resource's performance against PJM's expectations.[51] Therefore, PJM proposes to revise the current practice of using power metrics (MW) as inputs to the equation for calculating real-time energy make whole credits with an energy metric, TRLD MWh.[52]

i. Calculating TRLD MW

TRLD MW (power) and TRLD MWh (energy) (together "TRLD") are used to calculate real-time energy make whole credits.[53] TRLD MW is a resource's expected power output at the beginning of a Real-time Settlement Interval.[54]

PJM is proposing Tariff revisions to specifically set forth how a resource's TRLD MW is derived. First, proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(i) describes how TRLD MW is calculated at the start of the initial Real-time Settlement Interval t_0, with variations for soak and nosoak resources, and how TRLD MW is calculated in Real-time Settlement Intervals following t_0.[55]

---

[50] Joel Romero Luna, *Tracking Ramp Limited Calculation*, Monitoring Analytics (June 10, 2024), https://www.monitoringanalytics.com/reports/Presentations/2024/IMM_MIC_Tracking_Ramp_Limited_Calculation_20240610.pdf (describing transition from reliance on power to energy metrics in real-time make whole payment calculations).

[51] Morelli Aff. ¶ 14.

[52] Proposed Tariff, Attachment K-Appendix 3.2.3(e-1)(iv) ("The [TRLD] MW (power) and unadjusted [TRLD] MW (power) metrics will be converted to the [TRLD] MWh (energy) metrics that shall be used in the calculation of balancing Energy Make Whole credits and generator deviations.").

[53] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(i).

[54] *Id.*

[55] Morelli Aff. ¶¶ 15-38; *see* proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(i).

Second, proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(ii), sets forth how a resource's unadjusted TRLD MW is calculated at the start of the initial Real-time Settlement Interval t_0, with variations for soak and no soak resources, and in Real-time Settlement Intervals following t_0.[56]

Third, proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(iii) sets forth when PJM will stop calculating a resource's TRLD MW and unadjusted TRLD MW. PJM will continue to calculate TRLD MW and unadjusted TRLD MW until the resources goes offline unless the resource fails to follow PJM's instructions by, for example, tripping, or having the resource taken offline by the Market Participant. This provision of the proposed Tariff also explains how TRLD MW and adjusted TRLD MW are calculated when a resource is incrementally ramped down.

For each of the Real-time Settlement Intervals following the start of the TRLD MW calculation(t_0) until the resource is released, TRLD MW is equal to the TRLD MW at the beginning of the directly preceding interval plus or minus the increase or decrease in output (i.e., ramp) based on the dispatch run LMPs solved in the corresponding Real-time Security Constrained Economic Dispatch case and the ramp rates submitted by the resource.[57] Thus, TRLD MW in each Real-time Settlement Interval after the start of a resource's commitment until the resource is released is derived by applying the following calculation:

$$TRLD\ MW_t\ (power) = TRLD\ MW_{t-1} \pm Ramp_t$$

Where:

t = *Start time of Real-time Settlement Interval for which the metric is being calculated*

[56] Morelli Aff. ¶¶ 39-47; *see* proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(ii).

[57] Proposed Tariff, Attachment K- Appendix, section 3.2.3(e-1)(i).

> *Ramp = Increase or decrease in MW calculated using the Real-time [LMP] from the dispatch run at the applicable pricing point, the resource's Final Offer, and the ramp rate parameters.*[58]

The Morelli Affidavit provides a detailed, step-by-step explanation of how TRLD MW is derived and the various adjustments that may need to be made to the metric.[59]

ii. Calculating TRLD MWh

Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(iv) sets forth how the TRLD MW and unadjusted TRLD MW power metrics are converted into the energy metrics that are actually used in calculating make whole credits and deviation charges for Real-time Settlement Intervals prior to start time t_0, after PJM releases a resource to come offline, and in all other Real-time Settlement Intervals.

As Ms. Morelli explains in her affidavit, before start time t_0, a resource's Actual MWh[60] will be used in place of TRLD MWh and unadjusted TRLD MWh in the calculation of real-time energy make whole credits "[f]or all Real-time Settlement Intervals prior to the start time of [TRLD MW] calculations, t_0[.]"[61] Using Actual MWh is appropriate here, "the resource is typically ramping up [before its start time] and may not be following a linear ramp rate."[62]

After PJM releases the generation resource to come offline, if the resource's Actual MWh is below Economic Minimum, the resource's Actual MWh will be used in place of

[58] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(i).

[59] Morelli Aff. ¶¶ 15-52.

[60] Actual MWh is a new defined term in proposed Tariff, Definitions A – B, in accordance with Tariff, Attachment K-Appendix, section 3.1A.

[61] Morelli Aff. ¶ 54; Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(iv).

[62] Morelli Aff. ¶ 54. In addition, proposed Tariff, Attachment K-Appendix, sections 3.2.3(e-2)(i) and 3.2.3(e-2)(ii) limit a no soak resource's real-time energy make whole payment to Economic Minimum.

TRLD MWh and unadjusted TRLD MWh to calculate real-time energy make whole credits. Once operating below Economic Minimum, a resource's ramp rate down to zero may not be linear. Using the resource's actual output in this operating range, as Ms. Morelli explains, ensures the resource is not held accountable to deviations and will be made whole to its actual output for these intervals as long as PJM is actually expecting the resource to ramp offline.[63]

Third, in all other Real-time Settlement Intervals, TRLD MWh will generally be the average of TRLD MW (or unadjusted TRLD MW) at the start and at the end of each Real-time Settlement Interval. More specifically, TRLD MWh will equal to "the expected energy produced between the start of the Real-time Settlement Interval and the end of the Real-time Settlement Interval based on the [TRLD MW] at the start and at the end of the Real-time Settlement Interval and the resource's ramping capability, as further described in the PJM Manuals."[64]

c. Benefits of proposed reform (examples)

The following examples demonstrate how the TRLD MWh metric improves PJM's ability to track how closely a resource operates in accordance with PJM's expectations for the resource over the course of the resource's commitment period and across five-minute intervals. Example 1 and Example 1-Extended demonstrate how the TRLD MWh metric is an improvement over the Dispatch Signal MW and Ramp Limited Desired MW metrics. Example 2 shows how the TRLD MWh metric represents an improvement to the LMP Desired metric.

[63] Morelli Aff. ¶ 55.

[64] *Id.* ¶ 56; proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(v).

In addition, while PJM is proposing to use an energy metric (MWh) to replace the status quo RT Desired MW metrics in the real-time make whole calculation, for purposes of simplifying the following examples, all values are expressed in MW (power) rather than MWh (energy).

i. Example 1: TRLD replaces Dispatch Signal MW as metric used to calculate real-time make whole credits and deviation charges

Example 1 focuses on Real-time Settlement Intervals 1 through 4 of a hypothetical, pool-scheduled resource's real-time commitment. The hypothetical resource is operating in the Real-time Energy Market at 100 MW at the beginning of Real-time Settlement Interval 0 with a ramp rate of 1 MW/minute.

In this first example, the Real-time LMP is low, indicating the resource is only economic to produce energy equal to its Economic Minimum output level of 70 MW throughout the Real-time Settlement Intervals, so the resource is being dispatched down towards that value. For purposes of this example, the applicable RT Desired MW metric is Dispatch Signal MW. In each Real-time Settlement Interval, 1 through 4, PJM instructs the resource to ramp down as far as possible in that interval.

However, assume the resource does not follow PJM's dispatch instructions by ramping down beginning in Interval 1, instead staying at its output of 100 MW in Intervals 1 through 3. The resource then begins ramping down at Interval 4. Because the resource has a ramp rate of 1 MW/minute, it reduces its output from 100 MW to 95 MW in Interval 4.

Example 1. Resource with 1 MW/min Ramp Rate Producing 100 MW When Signaled to Ramp Down

Real-Time Settlement Interval	**Actual Response to PJM Dispatch** (MW)*
1	100 MW
2	100 MW
3	100 MW
4	95 MW

* Under proposed rules would be measured in MWh (energy), this example uses MW (power) for simplicity

a) Example 1, Status Quo Dispatch Signal MW Metric

Under the status quo rules, PJM uses Dispatch Signal MW as one of the metrics to measure how well the resource is operating in accordance with PJM's dispatch instructions in each discrete five-minute Real-time Settlement Interval of the commitment period. However, Dispatch Signal MW is influenced by how well the resource is or is not following dispatch. This is because the starting point for calculating Dispatch Signal MW is the resource's current actual output at the time. For the sake of this example, assume the output level used as the starting point for calculating Dispatch Signal MW is the same as the actual output from the prior interval.

Based on the hypothetical generation resource in Example 1, the status quo Dispatch Signal MW in each interval is as follows:

Example 1. Dispatch Signal MW (Status Quo)

Real-Time Settlement Interval	**Actual Response to PJM Dispatch** (MW)*	**Status Quo Dispatch Signal MW** (MW)
0	100 MW	-
1	100 MW	95 MW
2	100 MW	95 MW
3	100 MW	95 MW
4	95 MW	95 MW

* Under proposed rules would be measured in MWh (energy), this example uses MW (power) for simplicity

The resource is operating at 100 MW in interval 0. In Interval 1, given system conditions, the resource is desired at as low a level of output as possible. Since the resource has a 1 MW/min ramp rate and can therefore only move 5 MW in the next 5 minutes, the dispatch signal for Interval 1 directs the resource to move to 95 MW. The Dispatch Signal MW in Intervals 2 through 4 of the above hypothetical resource remains at 95 MW. Because the starting point for the Dispatch Signal MW calculation is the resource's actual output, setting Desired MW to Dispatch Signal MW can make it appear as if PJM desired more MW from the resource than PJM actually would have desired had the resource been following dispatch all along, starting with Interval 1.

More specifically, starting at Interval 1, Dispatch Signal MW reflects that the resource should decrease to 95 MW. Because the resource's actual output remains at 100 MW, and system conditions continue to signal that the resource should ramp down as far as possible in Interval 2, the Dispatch Signal MW again reflects that the resource should decrease to 95 MW. The same happens in Interval 3. Although LMP justifies the resource operating at Economic Minimum rather than Economic Maximum, the Dispatch Signal is unable to send the resource any lower than 95 MW because the resource has not moved in response to the prior instructions, and the Dispatch Signal is limited by the unit's current output and ramp rate. In Interval 4, PJM continues to instruct the resource to ramp down, and the resource finally does ramp down from 100 MW to 95 MW.

When comparing the resource's actual output to the Dispatch Signal MW, the resource appears to have followed dispatch in Interval 4 and to have only deviated by a *de minimis* amount of 5 MW in Intervals 1-3, because under the status quo rules, PJM only reviews how closely a resource is following dispatch one Real-time Settlement Interval at

a time. It thus appears as if the deviation is minimal, because the resource's behavior is influencing the metric being used to determine how closely the resource is performing to PJM expectations.

b) Example 1, Proposed TRLD Metric

By instead relying on the proposed TRLD metric, PJM is able to recognize that the hypothetical resource should have been following the dispatch signal by ramping down at a rate of 1 MW/min starting in Real-time Settlement Interval 1. Unlike the status quo metrics, TRLD relies on the MW level the resource should have been at in the preceding Real-time Settlement Interval as the starting point for the calculation, rather than using the resource's current output. In this way, TRLD reflects the RT Desired MW level that would have resulted had the resource been operating as expected over consecutive intervals across the resource's commitment. Thus, as demonstrated below, compared to the Dispatch Signal MW results, the TRLD values in Intervals 1 through 4 are as follows:

Example 1. TRLD (Proposed Rule)

Real-Time Settlement Interval	**Actual Response to PJM Dispatch** (MW)*	**Proposed TRLD Values** (MW)*
0	100 MW	-
1	100 MW	95 MW
2	100 MW	90 MW
3	100 MW	85 MW
4	95 MW	80 MW

* Under proposed rules would be measured in MWh (energy), this example uses MW (power) for simplicity

The TRLD metric recognizes that, had the resource been operating in accordance with PJM's expectations from the beginning of its commitment, the MW output level should be 80 MW by Real-time Settlement Interval 4.

While relying on the TRLD metric leads to the same RT Desired MW result in Interval 1 as relying on Dispatch Signal MW, using the TRLD metric begins to make a difference in Interval 2.

TRLD equals $TRLD\ MW_t\ (power) = TRLD\ MW_{t-1} \pm Ramp_t$. Ramp is equal to the "[i]ncrease or decrease in MW calculated using the Real-time [LMP] from the dispatch run at the applicable pricing point, the resource's Final Offer, and the ramp rate parameters."[65] LMPs continue to be low, indicating the resource is only economic to produce energy equal to its Economic Minimum output level of 70 MW and should ramp down as far as possible given its ramp rate. Thus, with a ramp rate of 1 MW/min, the resource's resulting TRLD MW in Interval 2 is 90 MW based on the assumption that the resource moved to 95 MW in Interval 1.

Using the Dispatch Signal MW as the Desired MW under the status quo would have made the resource whole to 100 MW in Intervals 1 through 3 and 95 MW in Interval 4.[66] Based on PJM's proposed TRLD MWh metric, the resource would be made whole for fewer MW—i.e., 95 MW in Interval 1, 90 MW in Interval 2, 85 MW in Interval 3, and 80 MW in Interval 4.

[65] Proposed Tariff, Attachment K- Appendix, section 3.2.3(e-1)(i).

[66] This assumes that, under the status quo rules, the hypothetical resource is made whole to its actual output as long as it doesn't produce more than 110% of RT Desired MW. PJM Manual 28 at section 5.2.1 (Oct. 1, 2025) ("PJM calculates the resource's five minute interval real-time energy offer amount based on its applicable schedule's offer data, where the applicable schedule's offer is lesser of the Committed Offer and the Final Offer, and its Real-time MW for that five minute interval. **However, for any five minute interval where the resource's Real-time MW is greater than 110% of its Operating Reserve Desired MW, Operating Reserve Desired MW is used to determine the five minute interval real-time energy offer amount.** If PJM declares a Realtime Market Suspension, the Real-time MW is used to determine the five minute interval real-time energy offer amount." (emphasis added)) ("Manual 28").

Unlike the Dispatch Signal MW metric, TRLD MWh recognizes where the resource would have been in each Interval based on the assumption that the resource has been operating as expected by PJM from the beginning of the resource's commitment across multiple five-minute intervals.

In this example, relying on TRLD MWh demonstrates that, had the resource been operating as expected by PJM beginning in Real-time Settlement Interval 1, the resource would have been ramping down steadily over four consecutive Real-time Settlement Intervals. When applied across a block of contiguous Real-time Settlement Intervals, TRLD MWh tracks PJM's desired energy output from the beginning to the end of a resource's commitment. Thus, relying on TRLD MWh as the Desired MW used in the make whole credit calculation avoids making the over-generating resource in Example 1 whole to more MW than PJM would have desired had the resource been operating as expected by PJM beginning in Interval 1.

c) Example 1-Extended, Proposed TRLD Metric

In Example 1-Extended, PJM continues to instruct the hypothetical resource to ramp its output down as far as possible towards its Economic Minimum (70 MW). If the resource continues to ramp down toward Economic Minimum after Real-time Settlement Interval 4 and then remains at Economic Minimum once it has reached 70 MW, the TRLD metric will recognize the resource's efforts to comply:

Example 1-Extended. TRLD (Proposed Rule)

Real-Time Settlement Interval	**Actual Response to PJM Dispatch** (MW)*	**Status Quo Dispatch Signal MW** (MW)	**TRLD MW Values** (MW)*
0	100 MW	-	-
1	100 MW	95 MW	95 MW
2	100 MW	95 MW	90 MW
3	100 MW	95 MW	85 MW
4	95 MW	95 MW	80 MW
5	90 MW	90 MW	75 MW
6	85 MW	85 MW	70 MW
7	80 MW	80 MW	70 MW
8	75 MW	75 MW	70 MW
9	70 MW	70 MW	70 MW
10	70 MW	70 MW	70 MW

* Under proposed rules would be measured in MWh (energy), this example uses MW (power) for simplicity

In effect, while the resource's deviation from dispatch instructions in the first few intervals will continue to be reflected in the resource's real-time make whole credits in subsequent Real-time Settlement Intervals, by Real-time Settlement Interval 9, the resource will have caught up to where it should have been had it started operating as PJM expected beginning in Interval 1. Thus, as extended example 1 reflects, the TRLD metric is capable of capturing the impact of deviations from dispatch instructions in preceding Real-time Settlement Intervals, while also recognizing the resource's efforts to catch up to PJM's desired MW in subsequent Real-time Settlement Intervals.

ii. Example 2: TRLD Replaces LMP Desired MW as metric used to calculate real-time make whole credits and deviation charges

The following simplified example demonstrates the benefits of using TRLD in place of the LMP Desired MW metric. As previously noted, LMP Desired MW is typically used as the RT Desired MW metric when a resource is significantly deviating from dispatch, i.e., by more than 20%, or when a resource has taken some action to reduce flexibility. As the example demonstrates, the LMP Desired MW metric can be an

unrealistic representation of the output a resource could achieve based on the resource's ramping capability. By recognizing ramp rate limitations, TRLD better tracks to PJM's expectations of the resource in light of these limitations.

The hypothetical resource in this example is operating in the Real-time Energy Market at 100 MW in Real-time Settlement Interval 1, and the resource has a ramp rate of 2 MW/minute.[67]

In example 2, the Real-time LMP is low, indicating the resource is only economic to produce energy equal to its Economic Minimum output level of 40 MW throughout the intervals in this example, so the resource is being dispatched down towards that value. In Intervals 1 through 10, PJM instructs the resource to ramp its output down as far as possible towards its Economic Minimum (40 MW).

Rather than ramping down as PJM expected, the resource initially remains at 100 MW in Interval 1, and then ramps up in Real-time Settlement Intervals 2-5, before ramping down in Intervals 6-10. The resource significantly deviates from dispatch, and therefore the appropriate RT Desired MW metric in this second hypothetical is LMP Desired MW. The resource's actual response to PJM dispatch is as follows:

[67] All values in the following hypothetical are expressed in MW (power) rather than MWh (energy) for simplicity.

Example 2. Resource with 2 MW/min Ramp Rate Producing 100 MW When Signaled to Ramp Down

Real-Time Settlement Interval	**Actual Response to PJM Dispatch** (MW)*
0	100 MW
1	100 MW
2	110 MW
3	120 MW
4	130 MW
5	140 MW
6	130 MW
7	120 MW
8	110 MW
9	90 MW
10	80 MW

* Under proposed rules would be measured in MWh (energy), this example uses MW (power) for simplicity

As demonstrated in the table below, in Interval 1, the LMP Desired MW metric indicates that PJM desires the resource to be producing at 40 MW. Therefore, under the status quo rules, PJM only makes the resource whole to 40 MW of output:[68]

Example 2. LMP Desired MW (Status Quo)

Real-Time Settlement Interval	**Actual Response to PJM Dispatch** (MW)*	**LMP Desired MW Values** (MW)
0	100 MW	-
1	100 MW	40 MW
2	110 MW	40 MW
3	120 MW	40 MW
4	130 MW	40 MW
5	140 MW	40 MW
6	130 MW	40 MW
7	120 MW	40 MW
8	110 MW	40 MW
9	90 MW	40 MW
10	80 MW	40 MW

* Under proposed rules would be measured in MWh (energy), this example uses MW (power) for simplicity

[68] This assumes that, under the status quo rules, the resource is only made whole to the Desired MW when it generates in excess of 110% of Desired MW. PJM Manual 28, Section 5.2.1, at 46.

However, because the resource has a 2 MW/min ramp rate and is at 100 MW at the start of Interval 1, the resource could only have ramped down to 90 MW in Interval 1. Making the resource whole to only 40 MW holds the resource accountable to a physically infeasible expectation in light of the resource's 2 MW/min ramp rate limitation. Replacing the LMP Desired MW metric with TRLD allows PJM to recognize the resource's ramp rate limitation when calculating the resource's real-time energy make whole compensation.

Under the proposed TRLD metric, in Interval 1, PJM would make the resource whole to 90 MW based on the TRLD metric, whereas under the status quo LMP Desired MW metric, the resource would have only been made whole to 40 MW, a difference of 50 MW. In Interval 2, using the TRLD MW, PJM would make the resource whole to 80 MW, whereas the status quo LMP Desired Metric would have again made the resource whole only to 40 MW, a difference of 40 MW. Thus, the TRLD MW metric more appropriately reflects expectations for the resource that consider the resource's ramp rate limitations:

Example 2. TRLD (Proposed Rule)

Real-Time Settlement Interval	**Actual Response to PJM Dispatch** (MW)*	**TRLD MW Values** (MW)*
0	100 MW	-
1	100 MW	90 MW
2	110 MW	80 MW
3	120 MW	70 MW
4	130 MW	60 MW
5	140 MW	50 MW
6	130 MW	40 MW
7	120 MW	40 MW
8	110 MW	40 MW
9	90 MW	40 MW
10	80 MW	40 MW

* Under proposed rules would be measured in MWh (energy), this example uses MW (power) for simplicity

2. PJM proposes a balancing Energy Make Whole credit calculation to support a more transparent and intuitive methodology (proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2)).

a. Overview of status quo calculation

At the end of each Operating Day, PJM calculates the level of real-time energy make whole credits a resource should receive in the Segments and Real-time Settlement Intervals in which PJM has determined the resource to be eligible to receive such credits.[69] If the resource has operated at a loss within a Segment of the Operating Day—i.e., if the resource's total costs exceed their revenues in that Segment—the resource will receive make whole payments.

A resource's costs include Start-up Costs, No Load Costs, and Incremental Offer costs. Thus, if the revenues from PJM's energy and ancillary services markets, together with the resource's day-ahead uplift credits, have not sufficiently compensated the resource for a resource's Start-up, No-load, and Incremental Offer costs, real-time energy make whole credits cover the difference.

PJM calculates the amount of real-time energy make whole paid to a resource by applying a balancing Operating Reserves equation[70] to determine the difference between a resource's total Value (or revenues) and total Cost in each Segment of the Operating Day, without cross-over between Segments or Operating Days.[71] A simplified representation of the equation is:

[69] PJM determines whether a resource is eligible to receive real-time energy make whole payments in a given Real-time Settlement Interval pursuant to the eligibility rules addressed in section II.A.3, below.

[70] Tariff, Attachment K-Appendix, section 3.2.3(e).

[71] *Id.*

balancing Operating Reserve Credits = Max(Cost @ RT MW Used - Value @ Balancing Value MW Used), 0.[72]

The Morelli Affidavit further breaks down this equation into the calculations and inputs that underlie it.[73]

The status quo equation is applied to each Segment within an Operating Day.[74] First, within each Segment, the Cost and Value components are individually calculated for each Real-time Settlement Interval in which the resource is eligible to receive real-time energy make whole credits.[75] Second, the difference between Cost and Value in each Interval in a Segment is then summed.[76] Third, if the net cost is positive, i.e., Cost exceeds Value, the resource receives real-time make whole credits.[77] If net cost is negative, i.e. Value exceeds Costs, there is no need for additional compensation, and the real-time energy make whole value is set to $0.[78]

Under the status quo balancing Operating Reserve credits equation, when resources deviate from PJM's real-time dispatch instructions, the Real-time MW ("RT MW") reflected in the Cost and Value sides of the equation may differ, resulting in an apples-to-

[72] Morelli Aff. ¶ 62; Tariff, Attachment K-Appendix, section 3.2.3(e); Operating Agreement, Schedule 1, section 3.2.3(e); PJM, Market Implementation Committee Presentation, Lisa Morelli, Senior Director, Market Settlements, at 20. https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2024/20241209-special/item-01---bor-proposal-overview--december-2024.pdf.

[73] Morelli Aff. ¶¶ 62-63.

[74] Tariff, Attachment K-Appendix, section 3.2.3(e).

[75] *Id.*

[76] *Id.*; *see also* Tariff, Definitions T-U-V (24.0.0) ("Total Operating Reserve Offer" defining calculation of Cost).

[77] Tariff, Attachment K-Appendix, section 3.2.3(e); *see also* PJM, Market Implementation Committee Presentation, Lisa Morelli, Senior Director, Market Settlements, at 20-21. https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2024/20241209-special/item-01---bor-proposal-overview--december-2024.pdf.

[78] PJM, Market Implementation Committee Presentation, Lisa Morelli, Senior Director, Market Settlements, at 20-21. https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2024/20241209-special/item-01---bor-proposal-overview--december-2024.pdf.

oranges comparison in the equation.[79] The Morelli Affidavit demonstrates why and how an apples-to-oranges comparison occurs by breaking down the status quo equation into the inputs and calculations that underlie it.[80] At bottom, the apples-to-oranges comparison may give rise to balancing Operating Reserve credit values that "include assumed revenues (Value) based on more RT MW than are reflected on the Cost side of the equation, particularly when resources deviate from PJM's dispatch instructions. Thus, under the current mechanism, the real-time energy output to which a resource should be made whole (Cost) and the real-time energy output for which the equation assumes the resource has been paid (Value) may differ."[81]

b. Proposed balancing Energy Make Whole credit calculation

PJM is proposing to replace the status quo balancing Operating Reserves credit equation with a three-step balancing Energy Make Whole credit equation. While broadly maintaining the existing *Max(Cost – Value, 0)* framework, the proposed calculation improves PJM's ability to make resources whole to their Costs, not to exceed the amount the resource would have been entitled to if it had operated consistent with PJM's expectations.[82] The proposed equation avoids the apples-to-oranges comparison between

[79] Morelli Aff. ¶¶ 71-72.

[80] *Id.* ¶¶ 62-72.

[81] *Id.* ¶ 72.

[82] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2) ("For generating resources, balancing Energy Make Whole credits received pursuant to this section shall be equal to the lesser of the tracking desired balancing Energy Make Whole credit, as calculated in Step 1 below in Tariff, Attachment K-Appendix, section 3.2.3(e-2)(i), and the actual balancing Energy Make Whole credit, as calculated in Step 2 below in Tariff, Attachment K-Appendix, section 3.2.3(e-2)(ii), for each Segment in the Operating Day, except as provided in this Tariff, Attachment K-Appendix, section 3.2.3(m)").

the Real-time energy output on the Cost and Value sides of the equation by breaking the calculation down into three steps.[83]

In brief, Step 1 of the proposed three-step equation is to calculate, for each Segment in a resource's Operating Day, the Tracking Balancing Energy Make Whole Credit using TRLD MWh.[84] Step 2 is to calculate, for each Segment in a resource's Operating Day, the Actual Balancing Energy Make Whole Credit using Actual MWh.[85] Step 3 is to compare the results derived in Step 1 and Step 2 of the calculation. The lesser of the two results is the amount to which a resource will be made whole for that Segment of the Operating Day through real-time energy make whole credits.[86]

The proposed three-step equation makes a resource "whole to its costs while also limiting the real-time energy make whole credits to the amount the resource would have been entitled to had it operated as PJM expected in the Real-time Energy Market."[87] The three-step equation avoids including assumed revenues that the resource would not have been able to attain, even if it had followed dispatch.[88] While the proposed balancing Energy Make Whole credit equation breaks down the calculation into three steps, it nonetheless continues the practice of calculating real-time energy make whole for a Segment within the Operating Day based on the difference between Cost and Value, floored at zero.[89]

---

[83] Morelli Aff. ¶¶ 71-80.

[84] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2)(i).

[85] *Id.* section 3.2.3(e-2)(ii).

[86] *Id.* section 3.2.3(e-2).

[87] Morelli Aff. ¶ 60.

[88] *See id.* ¶ 154.

[89] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2).

i. Step 1 of the proposed balancing Energy Make Whole credit calculation

Step 1 of the balancing Energy Make Whole credit equation is to determine the Tracking Balancing Energy Make Whole credit for the relevant Segment of a resource's Operating Day.[90] To do so, it is necessary to first calculate the Tracking Balancing Net Revenue for each Real-time Settlement Interval in the relevant Segment, which is the difference between Cost and Value using TRLD MWh.[91] In other words, PJM assumes that the resource produced TRLD MWh in each Real-time Settlement Interval in the Segment on both the Cost and the Value sides of the equation.[92] In conceptual terms, the proposed Step 1 equation for calculating Tracking Balancing Net Revenue is the difference between the resource's Cost (represented below in green) and Value, i.e. revenues (represented below in blue), of operating as expected throughout the entire commitment period:

Tracking Balancing Net Revenue = Cost @ TRLD MWh – Value @ TRLD MWh (floored at zero)

The proposed Tracking Balancing Net Revenue equation flips the ordering of Cost and Value and subsequently applies a -1 multiplier to match how PJM represents the net of Value and Costs (i.e. net profits and losses) in settlements reports. The equation Max(Cost – Value), 0 is functionally equivalent to Max((Value – Cost) *-1), 0.

$$\textit{Tracking Balancing Net Revenue}_t = (\textit{DA Revenue}_t + \textit{Balancing Revenue}_t + \textit{Other Market Revenue}_t + \textit{Opportunity Cost Owed}_t) - \textit{Real-time Cost}_t$$

[90] Morelli Aff. ¶ 74.

[91] *Id.*

[92] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2)(i).

Each of the above components of the Tracking Balancing Net Revenue equation in Step 1 consists, in turn, of underlying equations and inputs, which are set forth in detail in the Morelli Affidavit.[93]

Next, in Step 1, PJM calculates the difference between a resource's Tracking Balancing Net Revenue and Day-ahead Make Whole credit to derive the resource's Tracking Balancing Energy Make Whole Credit for each Segment in an Operating Day. Tracking Balancing Net Revenue represents the amount of make whole credit the resource would have been entitled to in a Segment if the resource had produced the desired MW and operated as PJM expected. If the Segment is the first Segment, this amount is reduced by the total Day-ahead Make Whole credit the resource has received. More precisely, as set forth in the Tariff, the proposed Step 1 equation is:[94]

Tracking Balancing Energy Make Whole Credit = A – B

Where

$A = -1 \times \sum t$ *Tracking Balancing Net Revenue*$_t$

Where

t = the eligible Real-time Settlement Intervals in the applicable Segment

B = Day-ahead Energy Make Whole Credit as determined pursuant to section 3.2.3(b) if the Segment is the first Segment. For all other Segments, B = 0.

Tracking Balancing Energy Make Whole Credit shall not be less than zero.

ii. Step 2 of the proposed balancing Energy Make Whole credit calculation

Step 2 of the balancing Energy Make Whole credit equation is to determine the Actual Balancing Energy Make Whole credit for the relevant Segment of a resource's

[93] Morelli Aff. ¶¶ 93-133.

[94] *Id.* ¶¶ 134-135; proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2)(i).

Operating Day.[95] To do so, it is necessary to first calculate the Actual Balancing Net Revenue for each Real-time Settlement Interval in the relevant Segment, which is the difference between Cost and Value, floored at zero, using Actual MWh.[96] This represents the amount of make whole credit a resource would require based on how it actually operated, inclusive of any deviations from PJM commitment and dispatch instructions.

As set forth in the Tariff, the proposed Step 2 equation is structurally identical to the Step 1 equation, *except* in the Step 2 equation: (1) TRLD MWh is replaced with Actual MWh; (2) inputs into Other Market Revenue represent actual amounts credited to the resource; and (3) Opportunity Cost Owed, addressed below in section II.A.2.b.iv, is not added into balancing net revenue.[97]

In conceptual terms, the proposed Step 2 equation for calculating real-time energy make-whole payments in a Segment of the resource's commitment period is the difference between the resource's Cost and Value (revenues) based on actual real-time output:

$$\textit{Actual MW Credit} = \textit{Cost @ Actual MWh} - \textit{Value @ Actual MWh (floored at zero)}$$

Similar to the proposed Tracking Balancing Net Revenue equation, the proposed equation for deriving Actual Balancing Net Revenue flips the ordering of Cost and Value and subsequently applies a -1 multiplier to match how PJM represents the net of Value and Costs (i.e. net profits and losses) in settlements reports.

$$\textit{Actual Balancing Net Revenue}_t = (\textit{DA Revenue}_t + \textit{Balancing Revenue}_t + \textit{Other Market Revenue}_t) - \textit{Real-time Cost}_t$$

[95] Morelli Aff. ¶ 74; proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2)(ii).

[96] Morelli Aff. ¶ 74; proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2)(ii).

[97] Morelli Aff. ¶ 139; proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2)(ii).

Each of the above components of the Actual Balancing Net Revenue equation in Step 2 consists, in turn, of underlying equations and inputs, as described by Ms. Morelli in her attached affidavit.[98]

Next, in Step 2, PJM calculates the difference between a resource's Actual Balancing Net Revenue and Day-ahead Make Whole credit to derive the resource's Actual Balancing Energy Make Whole Credit for each Segment in an Operating Day.[99] Actual Balancing Net Revenue represents the amount of make whole credit the resource would have been entitled to in a Segment based on how the resource actually operated. If the Segment is the first Segment, this amount is reduced by the total Day-ahead Make Whole credit the resource has received. More precisely, as set forth in the Tariff, the proposed Step 2 equation is:[100]

Actual Balancing Energy Make Whole Credit = A – B

Where

$A = -1 \times \sum_t$ *Actual Balancing Net Revenue*$_t$

Where

t = the eligible Real-time Settlement Intervals in the applicable Segment

B = Day-ahead Energy Make Whole Credit as determined pursuant to section 3.2.3(b) if the Segment is the first Segment; else, 0

Actual Balancing Energy Make Whole Credit shall not be less than zero.

[98] Morelli Aff. ¶¶ 140-149.

[99] *Id.* ¶ 150; proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2)(ii).

[100] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2)(i).

In addition, under certain scenarios, the results of the Step 1 and Step 2 calculations may need to be modified to reflect operational characteristics of no soak,[101] soak,[102] and Flexible Resources,[103] as further addressed in sections II.A.3.b.i and II.C.5, below.

iii. Step 3 of the proposed balancing Energy Make Whole credit calculation

In the third and final step of the proposed balancing Energy Make Whole credit equation, the resulting Tracking Balancing Energy Make Whole credit and Actual Balancing Energy Make Whole credit, calculated in Step 1 and Step 2, are compared.[104] The resource's real-time energy make whole credit in that particular Segment of the Operating Day equals the lesser of the two values.[105]

Balancing Energy Make Whole Credit = Min (Step 1 Credit, Step 2 Credit)

The effect of the revised rule is that resources are made whole to their Costs, but the real-time energy make whole payment is limited to the amount the resource would have been

[101] Proposed Tariff, Attachment K-Appendix, sections 3.2.3(e-2)(i), 3.2.3(e-2)(ii) (Balancing Revenue and Real-time Cost calculations for no soak resources in the Real-time Settlement Intervals preceding start of commitment cap the TRLD MWh or Actual MWh "at the minimum operating limit for such interval.").

[102] *Id.* (removing costs incurred and revenues received in applicable Real-time Settlement Intervals where soak resource is ramping up to Economic Minimum and is therefore not dispatchable during intervals where resource was scheduled to be online and running).

[103] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2)(i) ("During Real-time Settlement Intervals where a Flexible Resource is self-scheduled and was committed by [PJM] in the [Day-ahead Energy Market] for the same Real-time Settlement Interval, the above calculation will use the Tracking Balancing Net Revenues that the resource would have received if it had followed PJM real-time commitment instructions and remained offline; provided that if the unit is taken over by company to run as self-scheduled prior to the Minimum Run Time of a pool scheduled commitment elapsing, this shall only apply to those Real-time Settlement Intervals beyond the Minimum Run Time.").

[104] Morelli Aff. ¶ 74; proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2) ("For generating resources, balancing Energy Make Whole credits received pursuant to this section shall be equal to the lesser of the tracking desired balancing Energy Make Whole credit, as calculated in Step 1 below in Tariff, Attachment K-Appendix, section 3.2.3(e-2)(i), and the actual balancing Energy Make Whole credit, as calculated in Step 2 below in Tariff, Attachment K-Appendix, section 3.2.3(e-2)(ii), for each Segment in the Operating Day, except as provided in this Tariff, Attachment K-Appendix, section 3.2.3(m)").

[105] Morelli Aff. ¶¶ 151-153; proposed Tariff, Attachment K-Appendix section 3.2.3(e-2).

entitled to *if the resource provided the desired MW*.[106] An example of how this works in application is set forth in the Morelli Affidavit and accompanying Exhibit No. Morelli-0001.[107]

iv. Inclusion of additional inputs

PJM is also proposing to include a number of additional inputs to the proposed balancing Energy Make Whole credit equation that represent revenues either not reflected, or not fully reflected, in the status quo equation. Namely, PJM is proposing to include Company Responsible Negative Revenues, Other Market Revenue, and Opportunity Cost Owed components in the proposed balancing Energy Make Whole credit equation. Specifically, Company Responsible Negative Revenues consist of "any negative balancing revenues in excess of the Day-ahead Energy Market revenue that results from the Market Participant's actions reducing the resource's flexibility as further specified in the PJM Manuals."[108] "Other Market Revenue" reflects the offsetting revenue (potential or actual) earned from non-energy—i.e., from the Synchronized Reserve Market, Secondary Reserve Market, Non-Synchronized Reserve Market, the provision of Reactive Service, lost opportunity cost credits, and Regulation. "Opportunity Cost Owed" is "the sum of the potential opportunity costs owed for Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve as determined in accordance with [Tariff] Sections 3.2.3A(f)(iv), 3.2.3A.001(d)(iii) and 3.2.3A.01(f)(iv), respectively."[109] In basic terms, Opportunity Cost

[106] Morelli Aff. ¶¶ 151-153; proposed Tariff, Attachment K-Appendix section 3.2.3(e-2).

[107] Morelli Aff. ¶¶ 81-153.

[108] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2)(i).

[109] *Id.* (The calculations for Opportunity Cost Owed are set forth in Tariff, Attachment K-Appendix, sections 3.2.3A(f)(iv), 3.2.3.A.001(d)(iii), and 3.2.3A.01(f)(iv)).

Owed can be thought of as *negative* revenues from buying out of a Day-ahead Synchronized Reserve, Secondary Reserve or Non-Synchronized Reserve assignment that a resource was not made whole because the resource, rather than PJM, took an action that led to those negative revenues being incurred. A detailed explanation of each of these inputs is set forth in the Morelli Affidavit as part of the breakdown of the proposed equation therein.[110] At bottom, including these inputs will more completely reflect all of the revenues that can offset the costs to which a resource should be made whole through real-time energy make whole credits, thus enhancing transparency. Furthermore, in addition to improving transparency, including Other Market Revenue in the proposed equation obviates the need for less intuitive inputs that are used in the status quo balancing Operating Reserve credit equation such as Market Revenue Neutrality Offsets.

c. Benefits of proposed reforms

The benefits of the proposed balancing Energy Make Whole credit equation are readily apparent when considered in application. Ms. Morelli applies the balancing Energy Make Whole credit equation to a hypothetical resource, appended to Ms. Morelli's affidavit as Exhibit No. Morelli-0001.[111]

First, Exhibit No. Morelli-0001 demonstrates that the amount in real-time energy make whole credits the hypothetical resource can potentially receive is bounded by the amount in real-time energy make whole credits the resource would have been entitled to if had it operated in the Real-time Energy Market as PJM expected.

[110] Morelli Aff. ¶¶ 98-101, 103-119.

[111] *Id.*, Exh. No. Morelli-0001.

In Exhibit No. Morelli-0001, the resource under-performed in both Interval 1 and Interval 2 of Segment 1. In the first interval, the resource's Actual MWh value was 47 MWh, when TRLD MWh was 100 MWh.[112] In the second interval, the resource's Actual MWh value was 50 MWh when the TRLD was 75 MWh.[113] TRLD MWh in Interval 2 was adjusted down from the unadjusted TRLD MWh of 100 MWh, the hypothetical resource's Economic Maximum, to accommodate a Synchronized Reserve Market commitment.[114]

As Ms. Morelli explains, the Cost to which the resource would have been made whole had it operated as PJM expected in the Real-time Energy Market is lower than the Cost to the resource based on its Actual MWh performance.[115] The example demonstrates how, under the proposed equation, a resource is bound by the real-time energy make whole payments it could have earned had it performed as PJM expected, even if the resource's actual costs are higher based on the resource's actual performance.[116] In the example, the Tracking Balancing Energy Make Whole credit was $36.46, whereas the Actual Balancing Make Whole credit is $252.71.[117] Pursuant to Step 3 of the proposed equation, the resource is limited to being made whole to $36.46.[118] "While, based on the resource's actual performance in the Real-time Energy Market the resource incurred $252.71 in costs that were not covered by its revenue," Ms. Morelli explains, "the resource is only made whole

[112] Morelli Aff. ¶ 142, Exh. No. Morelli-0001 at 1.

[113] *Id.* ¶¶ 125, 148, Exh. No. Morelli-0001 at 2.

[114] *Id.* ¶ 128, Exh. No. Morelli-0001 at 2.

[115] *Id.* ¶¶ 151-153.

[116] *Id.*

[117] *Id.* ¶¶ 152-153.

[118] *Id.* ¶ 153.

to $36.46, which is the make whole credit that would have been necessary if the resource had operated as desired by PJM. Thus, the resource was *not* made whole for the $216.25 of its costs in excess of that value."[119]

Second, as demonstrated in Exhibit No. Morelli-0001, by breaking down the balancing Energy Make Whole credit equation into multiple steps, the proposed equation avoids making apples-to-oranges comparisons and is simpler and more intuitive than the currently effective equation. Step 1 determines how much the resource would have received had it followed PJM's expectations.[120] Step 2 determines how much the resource would have received based on its actual performance.[121] The hypothetical resource in Exhibit No. Morelli-0001, having deviated from PJM's expectations, incurred higher costs, but the resource is not made whole for those additional costs incurred, which were due to the resource's deviation from PJM's expectations.[122]

Under the proposed, three-step equation, the cost of deviating is readily apparent. Namely, the cost of deviating from PJM's expectations is easily determined by simply calculating the difference between the Step 1 credit and the Step 2 credit. Providing transparency into additional costs incurred or, at times, additional revenue left on the table when a resource is not following dispatch helps to incent resources to operate as directed by PJM.

[119] Morelli Aff. ¶ 153.

[120] *Id.* ¶¶ 88, 134-135, Exh. No. Morelli-0001.

[121] *Id.* ¶ 136, Exh. No. Morelli-0001.

[122] *Id.* ¶¶ 151-153, Exh. No. Morelli-0001 at 3.

In addition, the proposed equation includes Company Responsible Negative Revenues, Other Market Revenue, and Opportunity Cost Owed that were either not currently reflected, or not fully reflected, in the status quo equation.[123] Ms. Morelli demonstrates through Exhibit No. Morelli-0001, the inclusion of Other Market Revenue reflects inputs represented in the status quo Net Ancillary Services Profits component of the status quo equation while *also* including opportunity costs associated with the resource's provision of other products and services.[124]

For example, in Interval 2 of the hypothetical resource, the resource has a 0 MWh Synchronized Reserve Market commitment in the Day-ahead Energy Market, but then receives a Real-time commitment of 25 MWh in the Synchronized Reserve Market.[125] The TRLD MWh is adjusted down from the unadjusted 100 MWh to 75 MWh in order to reflect the headroom needed to provide the 25 MWh in Synchronized Reserve in the Real-time Energy Market.[126] Accordingly, the potential revenues from providing 25 MWh of Synchronized Reserve, as well as revenues from lost opportunity costs associated with the provision of Synchronized Reserve, are reflected in the Value side of Step 1 of the equation.[127] In Interval 2, as Ms. Morelli explains, "the resource forewent $61.46 of profit in the real-time energy market by providing only 75 MWh of energy (the Tracking Desired MWh) instead of 100 MWh of energy (the unadjusted Tracking Desired MWh) it would have been most profitable to produce in order to provide the 25 MWh real-time

[123] Morelli Aff. ¶¶ 98-101, 103-119.

[124] *Id.* ¶¶ 103-117.

[125] *Id.* ¶¶ 125, 147, Exh. No. Morelli-0001 at 2.

[126] *Id.* ¶ 128.

[127] *Id.* ¶¶ 129-130.

Synchronized Reserve assignment in this five-minute interval. Because the resource only earned $54.17 in balancing Synchronized Reserve Market clearing price credits, Lost Opportunity Cost credits provide the difference of $7.29 to ensure the resource earns enough to cover its opportunity cost."[128] The Other Market Revenue term in the proposed calculation includes both Synchronized Reserve Market Clearing Price Credits and Synchronized Reserve Lost Opportunity Cost Credits in order to capture the revenue paid to compensate a resource for opportunity costs in the synchronized reserve market.

3. PJM proposes revisions to the real-time make whole payment eligibility rules to align a resource's eligibility with its PJM commitment period (proposed Tariff, Attachment K-Appendix, section 3.2.3(e)).

a. Overview of status quo eligibility rules

Pursuant to the current Tariff, pool-scheduled resources "operat[ing] as requested by [PJM]" are eligible to receive real-time energy make whole credits.[129] However, being eligible to receive make whole payments in any given Real-time Settlement Interval does not guarantee that a resource will receive real-time energy make whole credits in that interval. Rather, when a resource is eligible in a given Real-time Settlement Interval, it means PJM will apply the balancing Operating Reserves credit equation to the resource's performance in that particular interval. Eligibility rules are thus distinct from the rules that govern how much in make whole payments a resource will be credited, which PJM is proposing to replace with a three-step balancing Energy Make Whole credit equation. Eligibility rules are also distinct from rules that dictate limits to the energy output a

[128] Morelli Aff. ¶ 131.

[129] Tariff, Attachment K-Appendix, section 3.2.3(e)(i).

resource is eligible to be made whole to, i.e., the RT Desired MW, which PJM is proposing to be based on the TRLD MWh metric.

At the end of each Operating Day, PJM evaluates each pool-scheduled resource in the Real-time Energy Market to determine when it is eligible to receive make whole payments.[130] "PJM determines eligibility for [real-time energy make whole] credits for each generating resource from dispatcher logs."[131]

Under the status quo rules, PJM considers a resource to be "operat[ing] as requested by [PJM]" and therefore eligible to receive real-time energy make whole credits during the resource's PJM-scheduled commitment from the time when the resource comes online until the resource goes offline consistent with PJM's directives, or is otherwise turned over to operate as a self-scheduled resource.[132] With exception to latitude given to start times of no soak resources, as described below, a resource's eligibility period is limited to the time in which the resource is online pursuant to PJM's commitment instructions.[133] In each Real-time Settlement Interval in which PJM deems a resource eligible to receive make whole payments, PJM applies the balancing Operating Reserves credit equation across all eligible Real-time Settlement Intervals within a Segment and assesses whether a resource's cost of performing in the Real-time market during the Segment in question exceeds the amount that the resource has already otherwise been paid in energy revenues and other offsetting revenues.[134]

[130] Tariff, Attachment K-Appendix, section 3.2.3(e).

[131] PJM Manual 28, section 5.2.1, at 44.

[132] Tariff, Attachment K-Appendix, section 3.2.3(e); PJM Manual 28 at section 5.2.1.

[133] Tariff, Attachment K-Appendix, section 3.2.3(e); PJM Manual 28 at section 5.2.1.

[134] Tariff, Attachment K-Appendix, section 3.2.3(e); PJM Manual 28 at section 5.2.1.

i. Status quo eligibility start

Under the status quo rules, eligibility start time differs depending on whether the resource is a soak or no soak unit. In brief, soak resources must reach Economic Minimum before they are eligible to receive real-time energy make whole credits.[135] Because the costs associated with ramping up to Economic Minimum are already included in a soak resource's Start-up Costs, beginning the eligibility period prior to the point when a soak resource has reached Economic Minimum would result in double-counting ramp-up costs.[136] Assuming the resource has reached Economic Minimum at the start time of the PJM commitment instruction, the eligibility start times of soak resources aligns with the start time of PJM's commitment instructions.

No soak resources are eligible to receive real-time energy make whole credits at the time when the resource is expected to be online and running for PJM in real-time, that is, the start time of the PJM commitment instruction. However, ramp-up costs are not included in the Start-up Costs of no soak resources.[137] If a no soak resource comes online early and begins ramping in preparation to follow dispatch at the start of the commitment, the resource may also be eligible for a period of time prior to the start of the commitment if the resource is determined to be ramping in preparation for the commitment.[138]

---

[135] Morelli Aff. ¶ 172.

[136] *Id.*; *see also* Tariff, Definitions R-S ("For units with a steam turbine and a soak process (nuclear, steam, and combined cycle), 'Start Fuel' is fuel consumed from first fire of start process (initial reactor criticality for nuclear units): Start-up Costs shall mean the net unit costs from PJM's notification to the level at which the unit can follow PJM's dispatch, and from last breaker open to shutdown.").

[137] Morelli Aff. ¶ 163; Tariff, Definitions R-S ("For units without a steam turbine and no soak process (engines, combustion turbines, Intermittent Resources, and Energy Storage Resources): Start-up Costs shall mean the unit costs from PJM's notification to first breaker close and from last breaker open to shutdown.").

[138] Morelli Aff. ¶ 163.

ii. Status quo eligibility end

Under the status quo rules, a resource's eligibility to receive real-time energy make whole credits ends "when any of the following conditions are met: a) the unit is taken over as self-scheduled; b) the unit trips; or c) PJM releases the resource, then the earlier of when a resource ramps down to 0 MW or three hours."[139]

b. Proposed revisions to real-time eligibility rules (proposed Tariff, Attachment K-Appendix, section 3.2.3(e))

PJM is proposing revisions to the status quo rules governing a resource's eligibility for real-time energy make whole credits. The proposed rules set forth clearer, more objective eligibility standards that expressly distinguish between soak and no soak resources and clearly dictate when a resource is eligible for real-time energy make whole credits.[140] With exception to the start time rules for no soak resources during ramp-up, discussed below, the revised rules ultimately increase the number of Real-time Settlement Intervals in which a resource is considered eligible for real-time energy make whole payments.[141]

If accepted by the Commission, the proposed eligibility rules, together with the proposed TRLD MWh metric and three-step balancing Energy Make Whole credit equation, would enable PJM to better measure how well a resource is operating compared to what PJM has requested of that resource—not only in terms of how closely a resource follows PJM's dispatch instructions in a given interval, but also in terms of how well the

[139] Morelli Aff. ¶ 166.

[140] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e).

[141] In addition, PJM is proposing to treat resources that are released, in the first Segment, within 30 minutes of the end of the resource's day-ahead commitment or Minimum Run Time, as staggered or late releases within the first Segment, rather than a new extension that would begin a second Segment. Proposed Tariff, Attachment K-Appendix, section 3.2.3(e)(ii).

resource performs throughout the resource's entire commitment period, even when the resource is offline. More specifically, by expanding the eligibility window to the beginning and end of a resource's PJM commitment, rather than limiting the eligibility window to the period when the resource is online or dispatchable, the proposed rules create benchmarks for what the resource's costs and revenues would have been if the resource had operated as expected, and the resulting maximum level of real-time energy make whole credits that a resource could have been paid by operating as PJM expected. The proposed revisions to the Tariff thus paint a more complete and comprehensive picture of the costs and revenues resulting from the PJM commitment and any resulting make whole payment that is necessary to cover the difference.[142] The way the proposed TRLD MWh metric and balancing Energy Make Whole credit equation work with the proposed eligibility rules to provide a more complete picture is explained further in the affidavit of Ms. Morelli.[143]

i. Proposed eligibility start

Under the proposed rules, eligibility begins at the first Real-time Settlement Interval of a resource's pool-scheduled commitment even if the resource is not yet online or dispatchable.[144] In order to avoid double-counting the ramping costs and revenues that soak resources include in their Start-up Costs, the proposed Tariff language adjusts the costs and revenues factored into the calculation, rather than starting eligibility late as the existing rules do. If a soak resource ramps up to Economic Minimum after the start of the

[142] *See* Issue Charge; Problem/Opportunity Statement.

[143] Morelli Aff. ¶¶ 173-202.

[144] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e)(i) ("A pool-scheduled generation resource's eligibility for balancing Energy Make Whole credits begins at the first Real-time Settlement Interval of a pool-scheduled commitment"); Morelli Aff. ¶ 162.

resource's pool-scheduled commitment period (as opposed to before it), the costs incurred and revenues received between the start of the commitment and the time the resource reaches Economic Minimum must be removed from the balancing Energy Make Whole calculation, since soak resources' Start-up Costs are already include the cost of ramping up to Economic Minimum. Under the proposed rules, the relevant costs and revenues are deducted as part of the proposed balancing Energy Make Whole credit.

In addition, PJM is proposing to replace the status quo rules that permit no soak resources to potentially receive real-time energy make whole credits if they are ramping up to meet a PJM commitment.[145] The revised rules would make a no soak resource eligible to receive make whole credits 20 minutes before the start of the resource's commitment period so long as incremental energy offer price MW pairs remain less than or equal to the first hour of PJM commitment, and without need for a subjective check.[146] As previously noted, ramp-up costs are not included in the Start-up Costs of no soak resources.[147] Thus, no soak resources can be made whole for ramping up to Economic Minimum prior to the start of the resource's commitment, as long as the period of eligibility is sufficiently short

[145] Proposed Tariff, Attachment K-Appendix 3.2.3(e)(i) ("Additionally, generation resource types with no soak process in the Start-up Cost are eligible for balancing Energy Make Whole credits for a pre-commitment period prior to the first Real-time Settlement Interval of the pool-scheduled commitment to account for ramping costs").

[146] *Id.* ("The pre-commitment period begins with the Real-time Settlement Interval when a generation resource comes online but may not begin earlier than four Real-time Settlement Intervals (20 minutes) prior to the first Real-time Settlement Interval of the pool-scheduled commitment").

[147] Morelli Aff. ¶ 163; Tariff, Definitions R-S ("For units without a steam turbine and no soak process (engines, combustion turbines, Intermittent Resources, and Energy Storage Resources): Start-up Costs shall mean the unit costs from PJM's notification to first breaker close and from last breaker open to shutdown.").

to prevent recovery of costs outside of the ramping period. The proposal does this through the allowance of an objective 20-minute ramping period.[148]

ii. Proposed eligibility end

Under the proposed rules, eligibility continues until either: (a) the later of the day-ahead commitment or Minimum Run Time or when PJM releases the resource, even if the resource stops running before the end of the commitment period, or (b) the resource is no longer running under the direction of PJM because it has, for example, tripped, been taken over by the Market Seller, or otherwise released by PJM.[149] Extending the eligibility period to Real-time Settlement Intervals after a resource stops running or is no longer running under the direction of PJM allows PJM to recognize the net revenue that resource would have earned if it had operated as directed by PJM for the entire commitment period.[150]

c. Benefits of proposed reforms

Under the current rules, with exception to no soak resources, generation resources are only eligible for real-time energy make whole credits during the period when they are actually online or dispatchable in the Real-time Energy Market. Eligibility starts when a resource is online or dispatchable and ends after ramp down when PJM releases the resource, when the resource is taken over by the Market Seller through a self-schedule, or when the resource trips.[151] The revised eligibility rules, on the other hand, would treat all

[148] The 20-minute ramping period was based on an analysis of ramping times for no soak resources. Morelli Aff. ¶ 164.

[149] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e)(i) ("The generation resource remains eligible for balancing Energy Make Whole credits until the later of: 1) the Real-time Settlement Interval corresponding to the end of its Day-ahead Energy Market commitment or the end of its Minimum Run Time, as applicable or 2) the Real-time Settlement Interval when the resource is no longer running under the direction of the Office of the Interconnection.").

[150] Morelli Aff. ¶ 168.

[151] Tariff, Attachment K-Appendix, section 3.2.3(e).

of the intervals in a resource's commitment period as eligible for real-time make whole payments, thus providing a more transparent and complete picture of the financial impacts of following or deviating from PJM's expectations.[152]

For example, under the status quo rules, if a resource is late for the start of its day-ahead commitment period, the late-starting resource would not be considered eligible in the intervals of the day-ahead commitment period before the resource is online or dispatchable.[153] During the intervals of the resource's commitment period prior to the resource's late start, the costs and revenues that the resource would have realized are not taken into consideration when determining the appropriate level of make whole payment.[154]

Likewise, a resource that is released early in real-time by PJM dispatchers, prior to the end of its day-ahead commitment, would not be eligible for make whole credits in the intervals of the commitment period after the resource has been released. In this case, the resource becomes ineligible to recover any costs incurred from buying out of its Day-ahead energy position at PJM's direction. Here, the negative revenues (essentially a cost) the resource is subjected to by following PJM dispatch instructions are not taken into consideration when determining the appropriate level of make whole payment.

Furthermore, if a resource is taken over by the Market Seller in the middle of a pool-scheduled commitment period, under the status quo rules, the resource would not be

---

[152] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e)(i) ("A pool-scheduled generation resource's eligibility for balancing Energy Make Whole credits begins at the first Real-time Settlement Interval of a pool-scheduled commitment. The generation resource remains eligible for balancing Energy Make Whole credits until the later of: 1) the Real-time Settlement Interval corresponding to the end of its [Day-ahead Energy Market] commitment or the end of its Minimum Run Time, as applicable[;] or 2)the Real-time Settlement Interval when the resource is no longer running under the direction of the Office of the Interconnection").

[153] Morelli Aff. ¶ 177.

[154] *See id.*

eligible in the intervals in which the resource is running for the company rather than for PJM.[155] In such a scenario, any profits (or positive net revenues) the resource earns while self-scheduled would not be available to help offset the Start-up Costs that must be covered through the make whole credit calculation, which may lead to higher make whole credits than the resource otherwise would have received if it had continued operating as a pool-scheduled resource consistent with PJM's initial commitment decision.

The revised eligibility rules would consider all intervals in a resource's commitment period to be eligible for real-time make whole payments, thus providing a more transparent and complete picture of the financial impacts of following or deviating from PJM's expectations over the course of the commitment period.[156]

Expanding the eligibility period provides a more complete picture of the consequences of deviating from PJM's Real-time commitment and dispatch instructions. When combined with the new, proposed real-time energy make whole credit calculation, the revised eligibility rules will result in a more transparent and intuitive calculation of real-time energy make whole credits that more clearly reflects the impact of a resource coming online early or late, or otherwise not operating as PJM expected, on the overall real-time energy make whole credited to the resource. The benefits of the revised eligibility rules, combined with the proposed real-time energy make whole credit calculation, are explained further through three examples, discussed below.

[155] Morelli Aff. ¶ 198.

[156] *Id.* ¶¶ 173-175.

4. Taken together, the proposed reforms improve alignment between real-time energy make whole credits and whether a resource has operated as PJM expected across the resource's commitment period.

The proposed real-time energy make whole eligibility rules, when combined with the proposed TRLD MWh metric and three-step balancing Energy Make Whole credit calculation, will more clearly reflect the financial impact of resources following and/or deviating from PJM's expectations in the Real-time Energy Market.

When considered in application, the overall benefits of the proposed rules are readily apparent, particularly where resources deviate from PJM's expectations. Ms. Morelli highlights the benefits of these rules in application using three examples.

In Example A of the Morelli Affidavit, a hypothetical soak resource, acting in response to PJM's instructions, starts earlier than its day-ahead commitment start time.[157] The proposed rules recognize that the resource's changed start time was in accordance with PJM's expectations and makes the resource whole accordingly, while also avoiding double-payment for costs already covered in the soak resource's Start-up Costs.

Under the status quo rules, the balancing Operating Reserve credit equation does not begin to apply until the first Real-time Settlement Interval in which the resource is online or dispatchable. However, the proposed rules would have the resource's eligibility start time begin earlier, at the revised start time. Assuming the level of Day-ahead MW ("DA MW") the resource was committed for in the Day-ahead Energy Market was greater than the RT MW produced while the resource soaked, the proposed earlier start time would permit the resource to be made whole for the additional cost of buying out of the Day-

[157] Morelli Aff. ¶¶ 176-184.

ahead Energy Market, which is a cost incurred by the resource in order to perform in accordance with PJM's instructions and expectations. The status quo rules would not capture these additional costs and revenues. Importantly, the proposed rules also avoid double-counting the soak resource's Start-up Costs. Because the costs associated with the resource's soak period are already included in a soak resource's Start-up Costs, the proposed Tariff requires that the costs associated with the energy produced during a soak resource's soak period be removed from Step 1 and Step 2 of the balancing Energy Make Whole credit equation.[158]

In Example B of the Morelli Affidavit, the resource trips before the end of its commitment period and thus does not perform as PJM expected.[159] Under the proposed rules, if a resource trips, PJM will continue to apply the TRLD MW and unadjusted TRLD MW equations to Real-time Settlement Intervals through the end of its commitment period, even after the resource is offline. By comparison, the status quo rules would end the resource's eligibility period when the resource goes offline. Using the TRLD MWh metric through the end of the resource's commitment period allows PJM to establish where the resource would have been desired had it continued to operate consistent with the initial commitment expectation. The TRLD MWh metric would track the desired MWh that the resource would have provided had it operated in accordance with PJM's expectations rather than going offline.

[158] Proposed Tariff, Attachment K-Appendix, sections 3.2.3(e-2)(i), 3.2.3(e-2)(ii) (reducing costs calculations by costs incurred and revenues received by soak resources in the applicable Real-time Settlement Intervals when resource is ramping up to Economic Minimum since costs may already be included in the Start-up Costs).

[159] Morelli Aff. ¶¶ 185-194.

In Example C of the Morelli Affidavit, the resource is taken over by the company in the middle of its commitment period and thus does not operate as PJM expected.[160] Under the status quo rules, the resource is not eligible during the self-scheduled period, and therefore the current balancing Operating Reserve credit calculation does not capture the full impact of the resource's operations during the commitment period. Any net revenues earned while the resource is self-scheduled are excluded from the make whole credit calculation. This means any profits (or positive net revenues) the resource earns while self-scheduled would not be available to help offset the Start-up Costs that must be covered through the make whole credit calculation, which may lead to higher make whole credits than the resource otherwise would have received if it had continued operating as a pool-scheduled resource consistent with PJM's commitment decision. Under the proposed rules, Step 1 of the balancing Energy Make Whole credit calculation would capture costs and revenues that the resource would have accrued had the resource performed as PJM expected throughout the duration of the original PJM commitment period. Step 2 would, on the other hand, capture the costs and revenues resulting from the resource's Actual MWh output for the duration of the original PJM commitment period, including the actual output during the period when the resource is self-scheduled. In this way, the proposed rules better capture all the costs and revenues during the entire commitment period.

[160] Morelli Aff. ¶¶ 195-202.

B. Conforming Changes to Generation Resource Deviations (proposed Tariff, Attachment K-Appendix, section 3.2.3(o))

1. Overview of status quo rules governing deviations

At the end of each Operating Day, PJM determines whether and how much in balancing Operating Reserve charges, i.e., deviation charges, each generation resource should be assessed. The amount assessed against a resource is based on the extent to which a resource has not followed PJM dispatch instructions by greater than an applicable de minimis "percentage off dispatch" or "MW off dispatch" threshold.[161] Deviation charges penalize resources for deviations above the allowable excused deviation threshold. These charges act as a proxy for imbalances and costs incurred by the PJM market flowing from the resource's deviation from PJM's commitment and dispatch instructions.

Deviation charges are assessed in every Real-time Settlement Interval unless the resource is otherwise exempt from deviation charges in that Interval. Dispatchable resources that have followed PJM's commitment and dispatch instructions in the Real-time Energy Market are *not* assessed deviation charges.[162] In addition, resources that have deviated within the excusable threshold percentage or MW off dispatch or that otherwise qualify for an automatic exemption will not be assessed deviation charges.[163]

To determine whether a resource must pay deviation charges, PJM first assesses if the resource has deviated from PJM's commitment and dispatch instructions. Under the

[161] Tariff, Attachment K-Appendix, section 3.2.3(o) ("To determine if a generation resource is following dispatch [PJM] shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the dispatch signal or the actual output and ramp limited desired MW value for each Real-time Settlement Interval.").

[162] *Id.* ("Dispatchable pool-scheduled generation resources and dispatchable self scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations.").

[163] *Id.* (setting forth parameters in which a resource "shall not be assessed balancing Operating Reserve deviations.").

status quo rules, PJM makes this determination by comparing the resource's actual Real-time output, RT MW, to the relevant Desired MW value.

The Desired MW metrics used to calculate deviations are: Ramp Limited Desired MW, Dispatch Signal MW, LMP Desired MW, or DA MW.[164] For purposes of assessing deviations, the appropriate metric against which PJM compares a resource's RT MW depends on the operational characteristics of the resource and how closely it has followed PJM's dispatch instructions. For resources that are not dispatchable, or in certain scenarios where the resource has tripped, the degree of deviation for a resource that is not following dispatch is calculated as the difference between RT MWh and DA MWh in each Real-time Settlement Interval.[165]

Because PJM recognizes that generation resources are not always able to follow PJM's dispatch instructions perfectly, PJM determines whether a resource has deviated above the applicable de minimis threshold based on a resource's "MW off dispatch and % off dispatch."[166]

[164] Tariff, Attachment K-Appendix, section 3.2.3(o).

[165] *Id.* ("If a resource is not following dispatch, and the resource has tripped, for the Real-time Settlement Interval the resource tripped and the Real-time Settlement Intervals it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh – Day-Ahead MWh. For resources that are not dispatchable in both the Day-ahead and [Real-Time Markets] balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh - Day-Ahead MWh.").

[166] *Id.* ("To determine if a generation resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the dispatch signal or the actual output and ramp limited desired MW value for each Real-time Settlement Interval. If the dispatch signal and the ramp-limited desired MW for the resource are unavailable, the Office of the Interconnection will determine the unit's MW off dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the dispatch LMP Desired MW for each Real-time Settlement Interval.").

Next, PJM must make additional determinations, including, as relevant here, assessing whether the resource qualifies for other exemptions from deviation charges.[167] Even if the resource does not qualify for any other exemptions from deviation charges, the resource will still be exempt from deviation charges in that interval if the generation resource has not deviated above the applicable de minimis "MW off dispatch and % off dispatch" threshold.[168]

If a resource has deviated above the applicable de minimis threshold and does not otherwise qualify for automatic exemptions from charges, PJM calculates the deviation charges to be assessed against the resource.[169] PJM is not proposing to revise the equation for deriving Real-time deviation charges.

2. Proposed, conforming revisions to replace Desired MW metrics with TRLD MWh metric when measuring deviations and to remove certain exemptions from deviations (proposed Tariff, Attachment K-Appendix, section 3.2.3(o))

Except in limited scenarios in which PJM will continue to rely on Day-ahead MWh, PJM proposes to use the TRLD MWh metric, as described in section II.A.1, above, to measure balancing Operating Reserve deviations. In addition, as previously noted, PJM is proposing to replace the term "balancing Operating Reserve deviations" with "deviations" going forward. Furthermore, PJM is proposing to remove a number of automatic exemptions to deviation charges, which will no longer be necessary once PJM begins

[167] *See, e.g.*, Tariff, Attachment K-Appendix, section 3.2.3(o) ("If a resource has a sum of the absolute value of generator deviations for an hour that is less than 5 MWh, then the resource shall not be assessed balancing Operating Reserve deviations for that hour."); PJM Manual 28 at section 5.3.2.3.

[168] Tariff, Attachment K-Appendix, section 3.2.3(o).

[169] *Id.*

relying on TRLD MWh. These conforming changes to PJM's deviation rules will be reflected in revised Tariff, Attachment K-Appendix, section 3.2.3(o).

First, PJM is proposing to replace the Dispatch Signal MW, Ramp Limited Desired MW, and LMP Desired MW metrics with the TRLD MWh metric,[170] thus aligning the metrics for measuring deviations for purposes of assessing deviation charges with the metrics described in section II.A.1.b, above, for purposes of assessing real-time energy make whole credits. However, for any Real-time Settlement Interval when a resource is non-dispatchable, as defined in Section 3.2.3(o), or when PJM is unable to calculate a TRLD MWh metric for the resource due to unavailable schedules or offer parameters, PJM proposes to continue the status quo practice of relying on DA MWh to measure deviations.[171] Using the proposed TRLD MWh metric to calculate deviations is necessary to conform PJM's assessment of deviations and resulting deviation charges with PJM's proposed use of TRLD MWh to determine the energy output level to which a resource is made whole through real-time energy make whole payments.

Second, PJM is also proposing to remove several automatic exemptions from deviation charges. In keeping with the status quo rules, deviation charges are assessed in all Real-time Settlement Intervals in which a resource is not exempt from deviation charges. To be clear, the proposed eligibility rules applicable to real-time energy make whole payments, discussed above in section II.A.3.b, will not apply to deviation charges.

---

[170] Proposed Tariff, Attachment K-Appendix, section 3.2.3(o) ("Generation resource deviations are calculated as the difference between a resource's Actual MWh, (which for purposes of this section is defined as the Revenue Data for Settlements), and [TRLD] MWh for each Real-time Settlement Interval except for the scenarios where day-ahead scheduled MWh are used in the calculation as defined below.").

[171] *Id.* ("Generation resource deviations are calculated as the difference between a resource's Real-time Settlement Interval MWh and day-ahead scheduled MWh, rather than [TRLD] MWh, when a resource is non-dispatchable for any Real-time Settlement Interval.").

Several existing exemptions will no longer be necessary once the new TRLD MWh metric is implemented. For example, in some circumstances, under the status quo rules, generators are automatically exempted from deviations because the units must alter their output in order to provide other services. A subset of those automatic exemptions will also be eliminated, because TRLD MWh will appropriately reflect the necessary adjustment to the Desired MW and negates the need for these blanket exemptions. The specific exemptions PJM proposes to eliminate are:

- Online resources backed down to provide Synchronized Reserves or secondary reserves and operating below DA MW. However, resources providing these services in offline mode (in the case of secondary reserve) or synchronous condensing mode will remain exempted since they will not be online providing energy and thus will not have a TRLD MWh;
- Online resources that are dispatched up or down for reliability, constraint control, or reactive and manual instruction (TRLD MWh will be adjusted to reflect those manual dispatch instructions);
- Online resources providing reactive services (unless the MVAR instruction is not captured in resources' economic dispatch in which case the exemption will remain); and

- Resources operating below 110% of Economic Minimum during a minimum generation ("Min Gen") event. (TRLD MWh will be able to move all the way down to emergency min during a Min Gen event).[172]

The above automatic exemptions are no longer necessary, because any adjustment to output necessary to provide other services will be reflected in the TRLD MWh metric. Maintaining the automatic status quo exemptions, by comparison, would permit resources to receive unnecessarily broad exemptions that would allow resources to deviate further from RT Desired MW than necessary to deliver the intended service. By using TRLD MWh rather than relying on automatic exemptions in these scenarios, PJM is able to measure deviations in a more precise and tailored manner.

Nevertheless, resources that deviate within the existing threshold of 10% of RT Desired MW or an hourly average of deviations equal to less than 5 MWh will continue to be exempt in keeping with the status quo rules.[173]

With respect to the hypothetical resource in Example 1-Extended, previously discussed in section II.A.1.c, above, the resource would be exempt from deviation charges in Real-time Settlement Intervals 1 (5% off dispatch) and 8 (7% off dispatch), in addition to not being assessed deviation charges in intervals in which the resource is operating as PJM expected, i.e., Real-time Settlement Intervals 9 and 10.

[172] *See* proposed Tariff, Attachment K-Appendix, section 3.2.3(o) (setting forth the remaining exemptions in which "[a] generation resource shall not be assessed deviations in a Real-time Settlement Interval if any of the following conditions occur for that interval").

[173] In addition, status quo automatic exemptions from deviation charges that PJM is not proposing to remove will remain unchanged.

Example 1-Extended with % Off Dispatch (Deviations)

Real-Time Settlement Interval	**Actual Response to PJM Dispatch** (MW)*	**TRLD MW Values** (MW)* **and % off Dispatch**
1	100 MW	95 MW (5% off dispatch)
2	100 MW	90 MW (11% off dispatch)
3	100 MW	85 MW (18% off dispatch)
4	95 MW	80 MW (19% off dispatch)
5	90 MW	75 MW (20% off dispatch)
6	85 MW	70 MW (21% off dispatch)
7	80 MW	70 MW (14% off dispatch)
8	75 MW	70 MW (7% off dispatch)
9	70 MW	70 MW (0% off dispatch)
10	70 MW	70 MW (0% off dispatch)

* Under proposed rules would be measured in MWh (energy), this example uses MW (power) for simplicity.

C. Other Conforming or Clarifying Revisions

PJM is proposing additional revisions to conform or clarify other rules impacted by the proposed reforms to the rules governing real-time make whole payments and deviation charges. These additional revisions address: (1) resources that offer limited flexibility through the Fixed Gen Flag or by clamping minimum and/or maximum operating limits; (2) violations of parameter limits; (3) Market Suspensions; (4) Reactive Services Make Whole Credits; (5) Flexible Resources; and (6) revisions to defined terms and non-substantive organizational changes to PJM's Tariff and Operating Agreement. Attachment A, Tables C.1 and C.2, provide keys to the following conforming or clarifying provisions.

1. Impact of proposed reforms on resources that have limited their flexibility through restricted offer parameters (proposed Tariff, Attachment K-Appendix, sections 3.2.3(e-1), 3.2.3(e-2), 3.2.3(o))

Resources may be offered into the Day-ahead and/or Real-time Energy Market(s) with limited flexibility. Like other generation resources, units offering with limited flexibility may be assessed real-time make whole credits and deviation charges to the extent PJM determines that resources have followed and/or deviated from PJM's dispatch instructions within each Segment of the Operating Day.

In particular, a resource operator may submit offers with limited flexibility by using a "Fixed Gen Flag" to indicate that the resource has inflexible operating parameters requiring it to run at a certain output level or follow a specific schedule. Additionally, resources may restrict their minimum and/or maximum offer parameters by "clamping" their minimum and/or maximum output limits. Resources have "clamped" their limits when they have increased their applicable minimum operating limit or decreased their applicable maximum operating limit in Real-time by more than 5% compared to the minimum and maximum operating limits in place at the time of the Day-ahead and/or Real-time commitment(s). There are a variety of reasons for resources to clamp their minimum and/or maximum output limits including, for example, operational challenges, fuel limitations or environmental restrictions. At bottom, clamping reduces a resource's dispatchable range.

Under the status quo rules, PJM determines whether resources using a Fixed Gen Flag or clamping their limits have followed dispatch instructions in the Real-time Energy Market based on the LMP Desired MW metric, with one exception. If the resource uses

the Fixed Gen Flag in both the Day-Ahead and Real-time Markets, then deviations are calculated using comparisons to DA MW.

To the extent PJM is proposing to replace the LMP Desired MW metric with TRLD MWh when calculating real-time energy make whole credits and assessing deviation charges, this change will apply equally to resources that have limited their dispatchability. As such, the benefits of replacing LMP Desired MW with the TRLD MWh metric described in section II.A, above, will apply to resources that have and have not limited their dispatchability.

a. Resources using Fixed Gen Flag: use of TRLD MWh metric to calculate real-time energy make whole credits

PJM proposes to use the TRLD MWh metric when calculating real-time make whole credits pursuant to the proposed balancing Energy Make Whole credit calculation regardless of whether or not resources have used Fixed Gen Flag to limit operating parameters during the Operating Day. In other words, in accordance with the proposed "Tracking Desired Economic Minimum" and "Tracking Desired Economic Maximum" provisions in proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1), the calculation of TRLD MW (power) will be based on the resource's submitted Economic Minimum and Economic Maximum and submitted ramp rate, except under specific circumstances described in the newly proposed provisions. Thus, for purposes of Step 1 of the balancing Energy Make Whole credits calculation, PJM will determine the credits that a flexibility-limited resource would have received had it followed dispatch based on the resource's minimum and maximum operating limits without consideration of the resource's Fixed Gen Flag limitations. However, the Fixed Gen Flag limitations will be reflected in Step 2

of the balancing Energy Make Whole credits calculation, which is based on the resource's actual output.

b. Resources using Fixed Gen Flag: DA MWh or TRLD MWh metrics to calculate deviation charges

For purposes of calculating deviation charges assessed to resources that have used the Fixed Gen Flag, PJM proposes conforming revisions to replace reliance on the LMP Desired MW metric with reliance on the DA MWh or the TRLD MWh metric. When a resource *is* dispatchable in the Day-ahead Energy Market and Fixed Gen Flag is used in the Real-Time Market, deviation charges will reflect the TRLD MWh metric, calculated using dispatchable limits. With respect to a resource that has used the Fixed Gen Flag in the Real-Time market and that is *not* dispatchable in the Day-ahead Energy Market either, the status quo rule remains in place; the resource's deviations will continue to be "the difference between a resource's Real-time Settlement Interval MWh and day-ahead scheduled MWh."[174]

c. Resources offering limited dispatchable range: TRLD MWh metric to calculate real-time make whole credits

PJM proposes to use TRLD MWh when determining the real-time make whole credits to be assessed to resources that have limited their dispatchable range by clamping their minimum and/or maximum MW. The "Tracking Desired Economic Minimum" and "Tracking Desired Economic Maximum" provisions in proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1) will apply. If the resource clamps its operating limits, thus reducing the dispatchable range that the resource offered at the time PJM committed the resource, under the proposed Tariff provision, TRLD MWh will reflect the operating limits

[174] Proposed Tariff, Attachment K-Appendix, section 3.2.3(o).

offered by the resource at the time of commitment, rather than the resource's real-time operating limits. Thus, the resource is held responsible for providing the flexibility that its offer parameters had indicated it could provide at the time of commitment.

As noted above, PJM proposes to add the provision, "Company Responsible Negative Revenues" in proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2). Company Responsible Negative Revenues ensures that the resource owner, not the market, is held responsible for costs associated with the resource's reduction in dispatchable range. Any losses associated with the reduction in dispatchable range will be excluded from the real-time make whole credit calculation. The proposed rule prevents a resource from being made whole for losses associated with buying back any of the MW that were derated.

d. Resources offering limited dispatchable range: TRLD MWh metric to calculate deviation charges

For a generation resource that has clamped its applicable minimum and/or maximum operating limit, PJM proposes conforming changes to replace reliance on the LMP Desired MW metric with the TRLD MWh metric when calculating deviation charges.

2. Violations of Parameter Limits (proposed Tariff, Attachment K-Appendix, section 3.2.3(e)(iii))

Under the status quo rules, generation resources that have operated outside of its approved unit-specific parameters (or outside any approved exceptions to such parameters), are not permitted to earn Operating Reserve Credits or otherwise be made whole unless the resource can demonstrate to PJM that the resource is operating outside of such parameters as a result of an actual constraint.[175]

[175] Attachment K-Appendix, section 3.2.3(e) ("A Generation Capacity Resource that operates outside of its unit-specific parameters will not receive Operating Reserve Credits nor be made whole for such operation

PJM proposes to replace this rule with proposed Tariff language that will add more specificity to the conditions in which a resource may and may not recover energy uplift credits.[176] Specifically, while a resource may continue to remain eligible for energy uplift credits, a Market Seller will not recover any costs incurred for the intervals where the submitted operating parameters exceed the approved unit-specific parameters and such parameter affects the MW dispatch level of the resource in a given settlement interval. Additionally, if the submitted parameters could lead to "committing the generation resource to produce energy for longer than it otherwise would have, the resource will not be eligible for the energy uplift credit calculation for the commitment duration."[177] Despite the proposed refinements, the proposed rule retains the status quo provision allowing resources that have exceeded their parameter limits the ability to remain eligible for energy uplift credits if they can demonstrate to PJM that they are operating outside of such parameters as a result of an actual constraint.[178]

when not dispatched by [PJM], unless the Market Seller of the Generation Capacity Resource can justify to [PJM] that operation outside of such unit-specific parameters was the result of an actual constraint.").

[176] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e)(iii) ("If a Market Seller submits an offer parameter that exceeds the applicable approved parameter limit on a parameter-limited schedule for a generation resource and such parameter affects the MW dispatch level of the resource in a given settlement interval, the resource will remain eligible for the energy uplift credit calculation but shall not recover any costs incurred during the affected settlement intervals. If such parameter impacts the commitment decision in a manner that could lead to [PJM] committing the generation resource to produce energy for longer than it otherwise would have, the resource will not be eligible for the energy uplift credit calculation for the commitment duration.").

[177] *Id.*

[178] *Id.* ("[a resource that] exceeds its approved parameter limits may still be eligible for energy uplift credits if the Market Seller of such resource can justify to the Office of the Interconnection that the need to operate outside of such unit-specific parameters was the result of an actual constraint.").

3. Impact of Market Suspensions on real-time make whole credits and deviation charges (proposed Tariff, Attachment K-Appendix, sections 3.2.3(e-2)(iii), 3.2.3(g), 3.2.3(q)(iii))

PJM also proposes clarifying language to address how real-time make whole credits and deviation charges are calculated in the event that PJM declares a Market Suspension. To be clear, PJM is not proposing to change the impact of Market Suspensions on how real-time make whole credits or deviations are calculated. The proposed language simply clarifies that the resource will be made whole to Actual MWh, which is, pursuant to the updated balancing Energy Make Whole calculation, reflected in Step 2 of the calculation.[179] The proposed Tariff language also clarifies that that deviations will not be assessed to resources in the event of a Market Suspension, since such charges are, and will continue to be, under the revised rules, assessed only to Real-time Load and Exports during a Market Suspension.

4. Reactive Services Make-Whole credits (proposed Tariff, Attachment K-Appendix, sections 3.2.3B(f), 3.2.3B(j))

PJM proposes conforming updates to Reactive Services Make Whole credits, which use a calculation similar to that used to determine real-time make whole credits. Reactive Services Make Whole credits may be paid to a generation resource that has been brought online or requested to increase output in order to provide VAR support. Resources that have been brought online to provide Reactive Services are eligible to recover their costs, to the extent not already covered by LMP, through these Reactive Services Make Whole credits. PJM proposes conforming changes to the Reactive Services Make Whole credits

[179] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2)(iii) ("If the generation resource is eligible during a real-time Market Suspension, the balancing Energy Make Whole credit shall be equal to the actual balancing Energy Make Whole credit, as determined in subsection 3.2.3(e-2)(ii) of this section.").

calculation by replacing the existing RT Desired MW metric with the TRLD MWh metric, consistent with PJM's above proposed reforms to real-time make whole credit calculations.[180]

5. Flexible Resources self-scheduled in Real-time Energy Market (proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2)(i))

PJM is proposing to add a Tariff provision to clarify how balancing Energy Make Whole credits are calculated for Flexible Resources that have been committed in the Day-ahead Energy Market and self-scheduled in the Real-time Energy Market.[181] A Flexible Resource is "a generating resource that must have a combined Start-up Time and Notification Time of less than or equal to two hours; and a Minimum Run Time of less than or equal to two hours."[182] Flexible Resources are not assumed to run in real-time for their entire day-ahead commitment. Instead, Flexible Resources remain offline until committed by PJM in real-time or self-scheduled. If not committed by PJM in real-time, Flexible Resources are eligible to receive lost opportunity cost credits to cover losses in excess of DA revenues from buying out of the Day-ahead Energy Market and/or forgone profits.[183] PJM proposes that, when a Flexible Resource has been committed in the Day-ahead Energy Market and self-scheduled in the Real-time Energy Market, Step 1 of the proposed balancing Energy Make Whole credit equation will use the net revenues the

[180] Proposed Tariff, Attachment K-Appendix, section 3.2.3B.

[181] Proposed Tariff, Attachment K-Appendix, sections 3.2.3(e-1)(i), 3.2.3(e-1)(ii) ("During Real-time Settlement Intervals where a Flexible Resource is self-scheduled and was committed by the Office of the Interconnection in the [Day-ahead Energy Market] for the same Real-time Settlement Interval, the above calculation will use the Tracking Balancing Net Revenues that the resource would have received if it had followed PJM real-time commitment instructions and remained offline; provided that if the unit is taken over by company to run as self-scheduled prior to the Minimum Run Time of a pool scheduled commitment elapsing, this shall only apply to those Real-time Settlement Intervals beyond the Minimum Run Time.").

[182] Tariff, Definitions E-F (40.0.0).

[183] Tariff, Attachment K-Appendix, section 3.2.3(f-1).

resource would have received if it had followed PJM commitment instructions and remained offline during the Real-time Settlement Intervals in which the resource was self-scheduled. Step 2 of the proposed balancing Energy Make Whole credit equation will reflect the resource's actual operation and will not be adjusted.

6. Revisions to defined terms and non-substantive changes

In addition to the aforementioned revisions to replace the use of the term Operating Reserves to describe make whole with the term Energy Make Whole, PJM is proposing a number of edits for organization and readability, revising certain terms, and adding new defined terms, as necessary. A key to these changes is set forth in Attachment A, Tables C.2 and C.3.

III. STAKEHOLDER CONSULTATION

This filing is the product of a joint effort between PJM and the Market Monitor that originated from a joint PJM-Market Monitor issue charge and problem statement.[184] With input from PJM stakeholders, PJM and the Market Monitor developed the market rules proposed herein during 14 special sessions of the MIC dedicated to clarifying the real-time energy make whole credit rules applicable to resources operating as requested by PJM.[185]

On July 23, 2025, the proposal was endorsed by the Markets and Reliability Committee with a sector-weighted vote of 4.611 in favor (the approval threshold was

[184] *See* Issue Charge; *see also* Problem/Opportunity Statement.

[185] *Issue Details: Operating Reserve Clarification for Resources Operating as Requested by PJM*, PJM Interconnection, L.L.C., MIC Special Sessions (https://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue=f9b3dbf5-4149-4ea6-9ad3-0c452ff9f386) (14 MIC Special Sessions held in 2023 and 2024, with one cancelled February 2024 special session).

3.335).[186] The Members Committee subsequently endorsed the proposal on August 20, 2025, by acclamation with no abstentions and objections.[187]

IV. EFFECTIVE DATE

PJM requests an unspecified effective date of December 31, 9998.[188] This requested effective date is necessary because PJM's proposed reforms to the uplift rules will require numerous and significant software updates. As a result, if the Commission accepts this filing, PJM will begin the process of updating the existing software and aim to implement the reforms described herein towards the beginning of 2027. In the meantime, upon Commission acceptance of this filing, PJM proposes to publish informational TRLD results in PJM's Market Settlement Reporting System beginning in 2026, which PJM will not use in any settlement calculations. Rather, this informational data will act as a transitional period to provide Market Participants with the time and necessary information to familiarize themselves with the new TRLD metric.[189] PJM therefore respectfully requests that the Commission approve the package of reforms, as proposed, with an unspecified effective date of 12/31/9998. Furthermore, PJM requests the Commission issue an order by December 8, 2025, 62 days from the date of this filing, so that PJM can know whether to proceed with the necessary software changes to implement the proposed reforms.

---

[186] *Markets & Reliability Committee Minutes*, PJM Interconnection, L.L.C., 1 (July 23, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/mc/2025/20250820/20250820-item-09a---mrc-report.pdf.

[187] *Members Committee Minutes*, PJM Interconnection, L.L.C. (Aug. 20, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/mc/2025/20250820/20250820-agenda.pdf.

[188] *See*, *e.g.*, Implementation Guide for Electronic Filing of Parts 35, 154, 284, 300, and 341 Tariff Filings at 10 (Nov. 14, 2016), https://www.ferc.gov/sites/default/files/2020-05/implementation-guide.pdf ("If the effective date is not known at the time of the filing, such as the effective date is contingent on FERC approval, . . . the date of 12/31/9998 must be used.").

[189] 2025 BOR Credit Reform Proposal Overview at 6.

V. CORRESPONDENCE

Correspondence and communications with respect to this filing should be sent to, and PJM requests the Secretary include on the official service list, the following:[190]

Craig Glazer
Vice President–Federal Government Policy
PJM Interconnection, L.L.C.
1200 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 423-4743
craig.glazer@pjm.com

Ryan J. Collins
Vivian W. Chum
Wright & Talisman, P.C.
1200 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 393-1200
collins@wrightlaw.com
chum@wrightlaw.com

Chenchao Lu
Associate General Counsel
PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403
(610) 666-2255
chenchao.lu@pjm.com

VI. DOCUMENTS ENCLOSED

This filing consists of the following:

1. This transmittal letter;
2. Attachment A: Key to the Proposed Tariff and Operating Agreement Sections Implementing Proposed Reforms;
3. Attachment B: Affidavit of Senior Director of Market Settlements, Ms. Lisa Morelli and Exhibit No. Morelli-0001;

[190] To the extent necessary, PJM requests waiver of Rule 203(b)(3) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.203(b)(3), to permit all the persons listed to be placed on the official service list for this proceeding.

4. Attachment C: Revisions to the Tariff in redlined and non-redlined format, as provided in electronic tariff filing format pursuant to Order No. 714);[191] and

5. Attachment D: Revisions to the Operating Agreement in redlined and non-redlined format, as provided in electronic tariff filing format pursuant to Order No. 714).[192]

VII. SERVICE

PJM has served a copy of this filing on all PJM Members and on the affected state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,[193] PJM will post a copy of this filing to the FERC filings section on its internet site, https://pjm.com/library/filing-order, and will send an email on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM Region,[194] alerting them that this filing has been made by PJM and is available by following such link. If the document is not immediately available by using the referenced link, the document will be available through the referenced link within twenty-four hours of the filing.

[191] *Electronic Tariff Filings*, Order No. 714, 124 FERC ¶ 61,270 (2008), *final rule*, Order No. 714-A, 147 FERC ¶ 61,115 (2014).

[192] *Id.*

[193] *See* 18 C.F.R. §§ 35.2(e) and 385.2010(f)(3).

[194] PJM already maintains, updates, and regularly uses email lists for all PJM Members and affected state commissions.

VIII. CONCLUSION

PJM requests that the Commission accept the enclosed revisions to the Tariff and Operating Agreement, effective 12/31/9998.

Respectfully submitted,

/s/ Vivian W. Chum

Craig Glazer
Vice President–Federal Government Policy
PJM Interconnection, L.L.C.
1200 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 423-4743
craig.glazer@pjm.com

Chenchao Lu
Associate General Counsel
PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403
(610) 666-2255
chenchao.lu@pjm.com

Ryan J. Collins
Vivian W. Chum
Wright & Talisman, P.C.
1200 G Street, N.W., Suite 600
Washington, D.C. 20005
(202) 393-1200
collins@wrightlaw.com
chum@wrightlaw.com

Counsel for
PJM Interconnection, L.L.C.

Attachment A

Key to the Proposed Tariff and Operating Agreement Sections Implementing Proposed Reforms

Attachment A: Key to Proposed Tariff and Operating Agreement Sections Implementing Proposed Reforms

A. REFORMS TO REAL-TIME ENERGY MAKE WHOLE CREDIT RULES

1. Rules Implementing TRLD MWh Metric to Replace Real-time Desired MW Metrics

A.1. Proposed TRLD Design Components	Tariff Att. K-Appx; OA Sched. 1	Description	Details
New TRLD MW (power) and MWh (energy) metrics	section 3.2.3(e-1)	Describing the TRLD calculation and business rules	Describes calculation of TRLD MW (power), Unadjusted TRLD MW (power) and TRLD MWh (energy) values. Explains how the expected power and energy outputs are calculated at Start Time, in Real-time Settlement Intervals after Start Time until End Time, and at End Time. Dictates use of Actual MWh at beginning and end of run time in some cases. Distinguishes between Adjusted and Unadjusted TRLD. • 3.2.3(e-1)(i): TRLD MW values (adjusted) • 3.2.3(e-1)(ii): Unadjusted TRLD MW values • 3.2.3(e-1)(iii): TRLD MW calculations in scenarios until the resource goes offline or, if taken offline, until the resource trips or is taken offline prior to later of Day-ahead Energy Market commitment or end of Min Run Time • 3.2.3(e-1)(iv): Conversion from TRLD MW (power) metrics to TRLD MWh (energy) metrics; reliance on Actual MWh at the beginning and end of a resource's run time in some scenarios • 3.2.3(e-1)(v): Further adjustments to TRLD MW and MWh values *3.2.3(e-1) also reflects Other Proposed Design Components set forth in C.1, below.

2. Rules Implementing Balancing Energy Make Whole Credit Calculation

A.2. Proposed Make Whole Calculation Design Components	Tariff Att. K-Appx; OA Sched. 1	Description	Details
Impact of deviating from dispatch on the balancing Energy Make Whole credit calculation Use of TRLD MWh to calculate balancing Energy Make Whole credits; inclusion of Company Responsible Negative Revenues, Other Market Revenue; inclusion of Opportunity Cost Owed in Step 1	section 3.2.3(e-2)	Describing proposed the balancing Energy Make Whole credit 3-step calculation	Equations for calculating balancing Energy Make Whole payments in three steps: • 3.2.3(e-2)(i): Step 1: Using TRLD MWh, calculate Tracking Balancing Net Revenue for each Real-time Settlement Interval in each Segment, then calculate Tracking Balancing Make Whole credit for each Segment • 3.2.3(e-2)(ii): Step 2: Using Actual MWh, calculate Actual Balancing Net Revenue for each Real-time Settlement Interval in each Segment, then calculate Actual Balancing Make Whole credit for each Segment in an Operating Day • 3.2.3(e-2): Step 3. Balancing Energy Make Whole Credit for each Segment in an Operating Day is equal to the lesser of the results of Step 1 and Step 2 • 3.2.3(e-2)(i) and 3.2.3(e-2)(ii): Reflect inclusion of Company Responsible Negative Revenues; inclusion of Opportunity Costs via the Other Market Revenue term • 3.2.3(e-2)(i): Reflects inclusion of Opportunity Cost Owed *3.2.3(e-2)(i) and (ii) also include Proposed Eligibility Design Components set forth in A.3, below, and also reflects Other Proposed Design Components set forth in C.1, below set forth in C.1, below.

3. Rules Implementing Revisions to Clarify Real-time Make Whole Payment Eligibility Rules

A.3. Proposed Eligibility Design Components	Tariff Att. K-Appx; OA Sched. 1	Description	Details
Eligibility for balancing Energy Make Whole credits	section 3.2.3(e)(i)	New language for eligibility rules during pool-scheduled commitment period, ramp up period (referred to as pre-commitment period), and during ramp-down (referred to as post-commitment period)	Subsection 3.2.3(e)(i) explains when a generation resource is eligible for balancing Energy Make Whole Credits • General eligibility: must be "*pool-scheduled generation resources that operate for at least one [interval] within the pool-scheduled commitment period*" • Eligibility start: first interval of pool-scheduled commitment period • Eligibility end: later of: (1) interval corresponding to end of resource's Day-ahead Energy Market commitment or the end of its Minimum Run Time, (2) interval when resource is no longer running under PJM direction, when a resource trips, PJM releases a unit, or the unit is taken over from resource operator • Pre-Commitment Period, Soak resource: not eligible during pre-commitment period prior to first interval to account for ramping costs • Pre-Commitment Period, No Soak resource: eligible during pre-commitment period which begins when resource comes online but cannot be more than 20 minutes prior to commitment interval, but only if incremental energy offer price and quantity is less than or equal to PJM commitment energy offer price and quantity for the first hour of commitment period; soak resources with cost in start-up cost are not eligible • Post-Commitment Period: eligible during post-commitment period but eligibility cannot extend beyond the interval in which the resource is no longer running under PJM direction, plus a set number of intervals depending on resource type as specified in Business Practice Manual 28 and only if incremental energy offer price and quantity is less than or equal to PJM commitment energy offer price and quantity for the last hour of commitment period
Segmentation of balancing Energy Make Whole credits	section 3.2.3(e)(ii)	Additional intervals resulting from a staggered release, rather than a true extension, are added to Segment 1	Section 3.2.3(e)(ii) sets forth the impact of a unit being released shortly after the end of the commitment on Segments within an Operating Day. If a unit is released within 30 minutes of end of DA commitment / min run, no new segment is created. This is considered a late or staggered release rather than a new extension: *if a generation resource is no longer running under the direction of the Office of the Interconnection within 30 minutes after the end of the first Segment, the first Segment will also include the remainder of the Real-time Settlement Intervals in which the resource operated at the direction of the Office of the Interconnection.* If unit is released > 30 min beyond end of DA commitment or min run, then it is considered an extension and a new segment begins, no change to status quo: *The second Segment will be defined as any block of contiguous Real-time Settlement Intervals the resource runs under the direction of the Office of the Interconnection in excess of the first Segment.* *3.2.3(e) also reflects Other Proposed Design Components set forth in C.1, below.

A.3. Proposed Eligibility Design Components	Tariff Att. K-Appx; OA Sched. 1	Description	Details
Cap on balancing Energy Make Whole credited to no soak resources during pre-commitment eligibility period	sections 3.2.3(e-2)(i)-(ii)	Step 1 and Step 2 of balancing Energy Make Whole calculation include caps on MW made whole for no soak resources during pre-commitment eligibility period	With respect to no soak resources eligible up to 20 min before commitment start, the MW for which balancing Energy Make Whole is credited in the pre-commitment period in Step 1 and Step 2 of the calculation is capped at RT Eco Min MW: *The above Balancing Revenue and Real-time Cost calculations shall be further modified for Real-time Settlement Intervals preceding the start of the commitment for generation resource types with no soak process in the Start-up Cost by capping the [TRLD MWh] at the minimum operating limit for such interval.* *The above Balancing Revenue and Real-time Cost calculation shall be further modified for Real-time Settlement Intervals preceding the start of the commitment for generation resource types with no soak process in the Start-up Cost, by capping the [Actual MWh] at the minimum operating limit for such interval.*
Prevent double-counting of revenues and costs accrued when a soak resource is ramping up to Eco Min	sections 3.2.3(e-2)(i)-(ii)	Step 1 and Step 2 of balancing Energy Make Whole calculation remove costs incurred and revenues received when a soak resource is ramping up to Eco Min during PJM commitment period	If a soak resource is ramping up to Eco Min during a period when the resource was scheduled to be dispatchable and eligible for Real-time energy make whole payments, the costs incurred and revenues received during that period will be removed from Step 1 and Step 2 of the calculation since they can already be included in Start-Up Costs: *The above Balancing Revenue and Real-time Cost calculations shall be reduced by the costs incurred and revenues received in the applicable Real-time Settlement Intervals for generation resource types with a soak process in the Start-up Cost when the [TRLD MWh (energy)] indicates the unit is not dispatchable by [PJM] during a Real-time Settlement Interval when it was scheduled to be dispatchable since those costs and revenues may already be included in the start-up cost as further defined in the PJM Manuals.* *The above Balancing Revenue and Real-time Cost calculations shall be reduced by the costs incurred and revenues received in the applicable Real-time Settlement Intervals for generation resources with a soak process in the Start-up Cost when the Actual MWh indicate the unit is not dispatchable by [PJM] during a Real-time Settlement Interval when it was scheduled to be dispatchable by [PJM] since those costs and revenues may already be included in the Start-Up Cost.*

B. CONFORMING CHANGES TO GENERATION RESOURCE DEVIATIONS RULES

B. Proposed Deviations Design Components	Tariff Att. K-Appx; OA Sched. 1	Description	Details
Use of TRLD MWh to determine generator deviations	section 3.2.3(o)	TRLD MWh used for the calculation of generator deviations except for scenarios listed as requiring the use of day-ahead MWh	*Generation resource deviations are calculated as the difference between a resource's Actual MWh, (which for purposes of this section is defined as the Revenue Data for Settlements), and Tracking Ramp Limited Desired MWh for each Real-time Settlement Interval except for the scenarios where day-ahead scheduled MWh are used in the calculation as defined below.*
Use of DA MWh to determine generator deviations	section 3.2.3(o)	Rules for the use of Day-ahead MWh in the generator deviation calculations	*Generation resource deviations are calculated as the difference between a resource's Real-time Settlement Interval MWh and day-ahead scheduled MWh, rather than Tracking Ramp Limited Desired MWh, when a resource is non-dispatchable for any Real-time Settlement Interval. For purposes of this provision, a resource will be considered non-dispatchable when any of the following conditions occur …*
MWh reference point for determining deviations from dispatch and % off dispatch	section 3.2.3(o)	Language specifies TRLD MWh is used except for scenarios requiring the use of DA MWh	Either $$Deviation\ Percentage = Abs\ [1 - \frac{Actual\ MWh}{Tracking\ Ramp\ Limited\ Desired\ MWh}]$$ or $$Day-ahead\ Deviation\ Percentage = Abs\ \left[1 - \frac{Actual\ MWh}{Day-ahead\ Scheduled\ MWh}\right]$$
Threshold for excusing deviations	section 3.2.3(o)	Retains status quo % off deviation excusals and hourly MW tolerance	No change from the status quo: *A generation resource shall not be assessed deviations for the Real-time Settlement Interval if its deviation percentage <= 0.10 (10 percent).* *If a resource has an hourly average of the absolute value of generator deviations that is less than 5 MWh, then the resource shall not be assessed deviations for each Real-time Settlement Interval in that hour. This calculation shall be done after netting is applied, where applicable.*

B. Proposed Deviations Design Components	Tariff Att. K-Appx; OA Sched. 1	Description	Details
Scenarios when generators are automatically exempt from deviations	section 3.2.3(o)	Language specifies business rules for exemptions	Status quo exemptions except resource is <u>no longer automatically exempt</u> when: • Backed down for real time synchronized reserves and operating below DA MW; Backed down for real time secondary reserves and operating below DA MW; • Manually dispatched (up or down) due to reliability / constraint control / reactive and manual instruction is reflected in TRLD; • Operating below 110% of eco min during min gen event *A generation resource shall not be assessed deviations in a Real-time Settlement Interval if any of the following conditions occur for that interval:* • *The resource is assigned pool-scheduled Regulation.* • *The resource is assigned pool-scheduled Real-time Synchronized Reserves as a synchronous condenser.* • *The resource is assigned pool-scheduled Real-time Secondary Reserves as a synchronous condenser.* • *The resource is assigned pool-scheduled Real-time Non-Synchronized Reserves.* • *The resource is assigned Real-time Synchronized Reserves and responded during a Synchronized Reserve Event.* • *Flexible Resources that are committed in the Day-ahead Energy Market and not committed by the Office of the Interconnection in the Real-time Energy Market and the resource is offline.* • *The resource is manually dispatched by the Office of the Interconnection and the manual instruction is not reflected in the Tracking Ramp Limited Desired MWh.* Despite removal of these exemptions, units that fall within the percentage or MW deviation thresholds continue to be exempt. *3.2.3(o) also reflects Other Proposed Design Components set forth in C.1, below.

C. OTHER REVISIONS

1. Other Prodposed Design Components

C.1. Other Proposed Design Components	Tariff Att. K-Appx; OA Sched. 1	Description	Details
Resources Using Fixed Gen Flag (Calculating balancing Energy Make Whole credits and deviation charges)	sections 3.2.3(e-1); 3.2.3(e-2)(i)	Reliance on TRLD MWh Metric when calculating balancing Energy Make Whole credits of resources using Fixed Gen Flag	Provisions applying TRLD MWh in 3.2.3(e-2)(i) as set forth in 3.2.3(e-1): *Tracking Desired Economic Minimum = the generation resource's minimum operating limit unless any of the following conditions occur,* • *If a resource is requested to increase output due to a transmission constraint or other reliability issue, Tracking Desired Economic Minimum = the lower limit from the manual dispatch instruction as directed by the Office of the Interconnection.* • *If the resource's minimum operating limit increases by more than 5% of the resource's minimum operating limit at the time of commitment, the minimum operating limit at the time of commitment will be used.* *Tracking Desired Economic Maximum = the generation resource's maximum operating limit unless any one of the following conditions occur:* • *If a resource is requested to decrease output due to a transmission constraint or other reliability issue, Tracking Desired Economic Maximum = the upper limit from the manual dispatch instruction as directed by the Office of the Interconnection.* • *If a resource's maximum operating limit decreases by more than 5% of the resource's maximum operating limit at the time of commitment, the maximum operating limit at the time of commitment will be used.*
	section 3.2.3(o)	Reliance on DA MWh or TRLD MWh Metric when calculating deviation charges of Resources Using Fixed Gen Flag	Provisions applying DA MWh or TRLD MWh in 3.2.3(o): *Generation resource deviations are calculated as the difference between a resource's Actual MWh, (which for purposes of this section is defined as the Revenue Data for Settlements), and Tracking Ramp Limited Desired MWh for each Real-time Settlement Interval except for the scenarios where day-ahead scheduled MWh are used in the calculation as defined below. …* *Generation resource deviations are calculated as the difference between a resource's Real-time Settlement Interval MWh and day-ahead scheduled MWh, rather than Tracking Ramp Limited Desired MWh, when a resource is non-dispatchable for any Real-time Settlement Interval. …* • *The generation resource is not dispatchable in the Day-ahead Energy Market and is not dispatchable in the Real-time Energy Market. For purposes of the generation resource deviation calculation, not dispatchable is defined as … intervals when a generation resource elects to provide a fixed output using the fixed generation parameter, or other not dispatchable processes as defined in the PJM Manuals.*

C.1. Other Proposed Design Components	Tariff Att. K-Appx; OA Sched. 1	Description	Details
Resources Offering Limited Dispatchable Range, i.e. Clamping EcoMin and/or EcoMax (Calculating balancing Energy Make Whole credits and Deviation Charges)	sections 3.2.3(e-1), 3.2.3(e-2)	Reliance on TRLD MWh and inclusion of Company Responsible Negative Revenues when calculating balancing Energy Make Whole credits of resources offering Limited Dispatchable Range	Provisions applying TRLD MWh in 3.2.3(e-1): *Tracking Desired Economic Minimum = the generation resource's minimum operating limit, as specified in Tariff, Attachment K-Appendix, section 3.2.3(e-1), unless any of the following conditions occur,* • *If a resource is requested to increase output due to a transmission constraint or other reliability issue, Tracking Desired Economic Minimum = the lower limit from the manual dispatch instruction as directed by the Office of the Interconnection.* • *If the resource's minimum operating limit increases by more than 5% of the resource's minimum operating limit at the time of commitment, the minimum operating limit at the time of commitment will be used.* *Tracking Desired Economic Maximum = the generation resource's maximum operating limit unless any one of the following conditions occur:* • *If a resource is requested to decrease output due to a transmission constraint or other reliability issue, Tracking Desired Economic Maximum = the upper limit from the manual dispatch instruction as directed by the Office of the Interconnection.* • *If a resource's maximum operating limit decreases by more than 5% of the resource's maximum operating limit at the time of commitment, the maximum operating limit at the time of commitment will be used.* Applying Company Responsible Negative Revenues in 3.2.3(e-2)(i) (Step 1): *Balancing Revenue = Balancing Energy Market Revenue in accordance with the following equation: (Tracking Ramp Limited Desired MWh ─ Day-ahead Scheduled MWh) × Real-time LMP ─ Company Responsible Negative Revenues* *Where: Company Responsible Negative Revenues = any negative balancing revenues in excess of the Day-ahead Energy Market revenue that results from the Market Participant's actions reducing the resource's flexibility as further specified in the PJM Manuals. This is calculated as:* *MW unavailable due to limited flexibility × Min (Day-ahead LMP ─ Real-Time LMP, 0)* *Apply Company Responsible Negative Revenues in 3.2.3(e-2)(ii) (Step 2):* *Same as above, except replace reflerences with Tracking Ramp Limited Desired MWh with Actual MWh*
	section 3.2.3(o)	Reliance on TRLD MWh when Calculating Deviation Charges of Resources Offering Limited Dispatchable Range	Provisions applying TRLD MWh in 3.2.3(o): *Generation resource deviations are calculated as the difference between a resource's Actual MWh, which for purposes of this section is defined as the Revenue Data for Settlements, and Tracking Ramp Limited Desired MWh for each Real-time Settlement Interval except for the scenarios where day-ahead scheduled MWh are used in the calculation as defined below.*

C.1. Other Proposed Design Components	Tariff Att. K-Appx; OA Sched. 1	Description	Details
Violating Parameter Limits	section 3.2.3(e)(iii)	Specifies impact on energy uplift credits and eligibility to receive credits based on type of parameter violation	If the violated parameter impacts the dispatch level of the resource in a given interval, the unit will remain eligible for uplift calculation but losses will be set to zero: *If a Market Seller submits an offer parameter that exceeds the applicable approved parameter limit on a parameter-limited schedule for a generation resource and such parameter affects the MW dispatch level of the resource in a given settlement interval, the resource will remain eligible for the energy uplift credit calculation but shall not recover any costs incurred during the affected settlement intervals.* If the violated parameter impacts the commitment decision in a way that could lead to running the unit for longer than it otherwise would have, the resource is ineligible for uplift credits for the commitment duration: *If such parameter impacts the commitment decision in a manner that could lead to [PJM] committing the generation resource to produce energy for longer than it otherwise would have, the resource will not be eligible for the energy uplift credit calculation for the commitment duration.* Retains status quo process allowing a resource that exceeds its parameter limits to request to remain eligible for energy uplift credits: *[a resource that] exceeds its approved parameter limits may still be eligible for energy uplift credits if the Market Seller of such resource can justify to the Office of the Interconnection that the need to operate outside of such unit-specific parameters was the result of an actual constraint.*
Market Suspension	section 3.2.3(e-2)(iii)	Impact of Market Suspension on Real-time Make Whole credits	In the event of a Market Suspension, if PJM or Independent Market Monitor for PJM deems that the resource failed to follow dispatch instructions, resource is ineligible for Balancing Energy Make Whole credits: *In the event of a real-time Market Suspension, if the Office of the Interconnection and the Market Monitoring Unit determine that the generation resource was not following dispatch instructions, the generation resource shall be ineligible for balancing Energy Make Whole credits.* Maintains status quo for resources eligible for Balancing Energy Make Whole credits during Market Suspension: *If the generation resource is eligible during a real-time Market Suspension, the balancing Energy Market Whole credit shall be equal to the actual balancing Energy Make Whole credit, as determined in subsection 3.2.3(e-2)(ii) of this section.*
	sections 3.2.3(g), 3.2.3(q)(iii)	Impact of Market Suspension on Deviation Charges	Deviations not assessed under Market Suspension, because status quo rules dictate charges only assessed to Real-time load and exports during a suspension. Revised section 3.2.3(g): *[PJM] shall allocate the charges … to load outside such region in megawatt-hours but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Tariff, Attachment K-Appendix, section 1.12.* Revised 3.2.3(q)(iii) notes that, if PJM declares a market suspension, PJM will: *allocate deviation charges to the ratio share of real-time load plus export transactions pursuant to Tariff, Attachment K-Appendix, section 3.2.3(q)(ii).*

C.1. Other Proposed Design Components	Tariff Att. K-Appx; OA Sched. 1	Description	Details
Conforming updates to Reactive Service Make Whole Credits	sections 3.2.3B(f), 3.2.3B(j)	TRLD MWh applied to Reactive Service Make Whole credit	Revised calculation subtracts TRLD MWh, as determined according to Tariff, Attachment K-Appendix, section 3.2.3(e-1) from resource's actual output. As set forth in 3.2.3B(f): Reactive Service Make-Whole Credit = *{(AG - TRLD MWh) x (UB - URTLMP)} where:* *AG equals the actual output of the unit;* *TRLD MWh equals the Tracking Ramp Limited Desired MWh determined according to Tariff, Attachment K-Appendix, section 3.2.3(e-1);* *UB equals the unit offer for that unit for which output, or charging, is increased, determined according to the lesser of the Final Offer or Committed Offer;* *URTLMP equals the real time LMP at the unit's bus; and* *where UB - URTLMP shall not be negative, except where applicable for an Energy Storage Resource Model Participant or a Hybrid Resource when instructed to increase charging.* 3.2.3B(j): clarifying addition of reference to section 3.2.3(e-2) re: how resource is credited with start-up and no-load fees.
Adjustments for Flexible Resources	section 3.2.3(e-2)(i)	Use net revenues resource would have received if it followed PJM commitment instructions	In the event that a flexible resource is self-scheduled in the Real-time Energy Market and is committed by PJM in the Day-ahead energy market for the same Real-time interval, the calculation in Step 1 will use the Tracking Balancing Net Revenues the resource would have received had it followed PJM's real-time instructions and remained offline. As set forth in 3.2.3(e-2)(i): *During Real-time Settlement Intervals where a Flexible Resource is self-scheduled and was committed by the Office of the Interconnection in the Day-ahead Energy Market for the same Real-time Settlement Interval, the above calculation will use the Tracking Balancing Net Revenues that the resource would have received if it had followed PJM real-time commitment instructions and remained offline; provided that if the unit is taken over by company to run as self-scheduled prior to the Minimum Run Time of a pool scheduled commitment elapsing, this shall only apply to those Real-time Settlement Intervals beyond the Minimum Run Time.*

2. Non-Substantive Revisions to Status Quo Rules

C.2. Status Quo Rules	Tariff Att. K-Appx; OA Sched. 1	Description of non-substantive change to Status Quo Rules
Load Response excluding shut down costs from the second segment	section 3.2.3(e)	Sentence moved from 3.2.3(e) to 3.3A.5(b). Section 3.3A.5(b) describes the calculation of balancing Energy Make Whole credits for Economic Load Response Participants
Balancing Energy Make Whole Segment rules	section 3.2.3(e)	Segment language restructured for readability

C.2. Status Quo Rules	Tariff Att. K-Appx; OA Sched. 1	Description of non-substantive change to Status Quo Rules
Balancing Energy Make Whole rules for import transactions	section 3.2.3(e-2)(iv)	Import transactions were previously grouped under the heading of pool-scheduled resources and made whole under the rules in 3.2.3(e) and treated similarly to generation resources. Since generation resources are now subject to the proposed balancing energy make whole calculations under 3.2.3(e-2)(i-ii) and measurement against TRLD MWh, import transactions are no longer treated the same as generation resources. The status quo balancing energy make whole payments for import transactions have been clarified and moved to new section 3.2.3(e-2)(iv).
Scheduling of Operating Reserves where "Operating Reserves" is operational use of term	section 3.2.3(a)	Language referring to the scheduling of Operating Reserve, using the operational definition of the term, moved to OATT Attachment K-Appendix, section 1.10.1(e)
Balancing Operating Reserve Cost Allocation	sections 3.2.3(b), 3.2.3(p)	Consolidated redundant language describing the Balancing Operating Reserve Cost Allocation methodology, which is the status quo process to categorize balancing Energy Make Whole credits as either deviations or reliability for charge allocations. The language previously in section 3.2.3(b) was retained and moved to section 3.2.3(p). Removed language previously in 3.2.3(p)
Allocation of energy make whole in Day-ahead for resources scheduled to provide Reactive Services	section 3.2.3(d)	Clean up change to note exclusion of Direct Charging Energy to conform the Tariff language with the calculation of Real-time load plus exports as described within other sections of Attachment K-Appendix, section 3.2.3 and 3.2.3B
Total Credits allocated to RTO deviations	section 3.2.3(g)	Included Market Suspension rule. Clarified the following: • Credits listed in (g) include any balancing Energy Make Whole credits paid to import transactions • Credits listed in (g) are allocated as charges to total RTO deviations
Calculation of deviation quantities used in assessing deviation charges	section 3.2.3(h)	• Restructured language for readability. This section now solely describes the following: 1) calculation of total daily deviations 2) deviation netting rules 3) rules for assigning deviations to the Eastern or Western regions • Moved rule for Black Start Service cost allocation to 3.2.3(p) • Added references to restructured 3.2.3(q) describing the status quo settlements charge calculation o Current Tariff language: The cost of Operating Reserves for the Real-time Energy Market for each Operating Day…shall be allocated and charged to each Market Participant based on their daily total of hourly deviations o Clarified Tariff language specifies the allocation is done based on pro rata share of daily total of hourly deviations
Load response deviation calculation and eligibility	section 3.2.3(o-1)	Reference to Attachment K-Appendix, section 3.3A as rule defining how accrued deviations will be charged.

C.2. Status Quo Rules	Tariff Att. K-Appx; OA Sched. 1	Description of non-substantive change to Status Quo Rules
Deviation charges and rates	section 3.2.3(q)	• Restructured language for readability and to clarify how charges are determined for each Market Participant ○ (q)(i) describes status quo categorization of reliability and deviations cost allocation buckets into the Eastern or Western region ○ NEW: (q)(ii) describes the calculation of Eastern, Western, and RTO region balancing uplift reliability charges ○ NEW: (q)(iii) describes the calculation of Eastern, Western, and RTO region balancing uplift deviation charges ○ (q-1)(i) describes the calculation of: 1.) Eastern and Western regional adder rates for reliability; and 2.) Eastern and Western regional adder rates for deviations ○ (q-1)(ii) describes the calculation of the RTO rate for reliability and the RTO rate for deviations

3. Revisions to Definitions or Terminology

C.3. Definition or Terminology Changes	Governing Document Sections	Description
Replace Operating Reserve terminology used to describe make whole credits and charges in settlement sections with Energy Make Whole, energy uplift, or deviation.	OATT Attachment K-Appendix, sections 1.10(d), 1.10.1A(f), 1.12, 3.2.3, 3.3A, 8.8 OA section 18.17.1(e) OA Schedule 1, sections 1.10(d), 1.10.1A(f), 1.12, 3.2.3, 3.3A, 8.8	• "Operating Reserve(s)" replaced with "Energy Make Whole" or "energy uplift" or "uplift" • "balancing Operating Reserve credits" replaced with "balancing Energy Make Whole credits" • "balancing Operating Reserve charges" replaced with "charges" • "Operating Reserve deviations" replaced with "deviations" • "Operating Reserve Credit" replaced with "Energy Make Whole credit" Energy uplift is the terminology used to categorize both Energy Make Whole and lost opportunity cost credits. In general, lost opportunity cost credits compensate resources for foregone profits, Energy Make Whole credits compensate resources for costs incurred in excess of revenues.
Definitions for new terms "Actual MWh", "Energy Make Whole", and "Tracking Ramp Limited Desired"	OATT—Definitions OA—Definitions	*"Actual MWh" is equal to the real-time output of a resource as defined by the Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Tariff, Attachment K-Appendix, section 3.1A and parallel provisions in Operating Agreement, Schedule 1, section 3.1A.* *"Energy Make Whole" shall refer to energy uplift provided to make a resource whole for costs incurred as specified in Tariff, Attachment K-Appendix, section 3.2.3 and parallel provisions in Operating Agreement, Schedule 1, section 3.2.3.* *"Tracking Ramp Limited Desired" shall mean the desired MW or MWh calculated pursuant to Tariff, Attachment K-Appendix, section 3.2.3(e-1) and parallel provisions in Operating Agreement, Schedule 1, section 3.2.3(e-1).*

Attachment B

Affidavit of Senior Director of Market Settlements, Ms. Lisa Morelli and Exhibit No. Morelli-0001 on behalf of PJM Interconnection, L.L.C.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	**)**	**Docket No. ER26-___-000**

AFFIDAVIT OF LISA MORELLI
ON BEHALF OF PJM INTERCONNECTION, L.L.C.

1. My name is Lisa Morelli. I currently serve as the Senior Director of Market Settlements for PJM Interconnection, L.L.C. ("PJM"). I have served in my current position since 2021 but have held numerous other positions at PJM since 2004. My business address is 2750 Monroe Blvd., Audubon, Pennsylvania, 19403.

2. I am submitting this affidavit on behalf of PJM in support of proposed reforms to rules pertaining to PJM's Real-time Energy Market make whole payments or credits, currently called balancing Operating Reserve credits or payments in PJM's Open Access Transmission Tariff ("Tariff") and Amended and Restated Operating Agreement of ("Operating Agreement"), as well as conforming changes to other rules, including those regarding deviation charges, i.e., Operating Reserve charges.[1]

3. In my capacity as Senior Director of Market Settlements, I am directly responsible for the development of market settlements rule changes through PJM's stakeholder process and overseeing a staff of market settlement specialists that support the same mission. My responsibilities include ensuring that PJM's market settlement calculations for the Day-ahead, Real-time, and Ancillary Services Markets support the market design objectives of creating efficient market outcomes that minimize the cost of procurement, meeting system reliability needs, and incentivizing Market Sellers to act in a manner that promotes system reliability.

4. The Market Settlements departments at PJM are responsible for the market settlement of all PJM electricity markets, including the Real-time Energy Market. The Market Settlements departments are responsible for calculating and distributing all payments and credits for all market transactions and transmission

[1] To the extent PJM Open Access Transmission Tariff, Attachment K-Appendix ("Tariff") and proposed revisions thereto are referenced throughout this affidavit, it can be assumed that PJM has proposed identical revisions to parallel sections of Amended and Restated Operating Agreement of PJM, Schedule 1 ("Operating Agreement").

usage within PJM and leading the design of enhancements to PJM's markets settlements calculations across cross-functional teams of subject matter experts and supporting such enhancements in the stakeholder process and before the Commission. The Markets Settlements departments are continuously analyzing and improving market settlement design structures.

5. Prior to assuming my leadership role in Market Settlements, I served as Director of Market Design. In that role, I was responsible for overseeing the development of design enhancements to PJM's market designs for various markets and supporting PJM Market Operations to ensure accurate technical implementation of rule changes that I oversaw. Before that, I served as Director of Capacity, Demand Response, and Compliance where I was responsible for the Capacity Market Operations, Demand Response Operations, and Performance Compliance groups at PJM. In that role, I was involved in the technical design of the current Minimum Offer Price Rules, which were implemented in response to the Commission's December 2019 Order.[2] Prior to that, I served as Manager of Real-Time Market Operations for PJM where I was directly responsible for the technical design, implementation, and daily operation of PJM's real-time markets including the Real-Time Energy Market, Regulation, Synchronized Reserve, and Non-Synchronized Reserve Markets, in addition to the Real-Time Security Constrained Economic Dispatch tool used by PJM's system operators.

6. I have worked at PJM since October 2004. I hold a Bachelor's degree in Business Administration from LaSalle University in Philadelphia, PA and a Master's degree in Business Administration from Villanova University in Villanova, PA.

I. PURPOSE OF AFFIDAVIT

7. My affidavit supports PJM's filing to enhance rules pertaining to real-time energy make whole payments in PJM, and to propose conforming or clarifying revisions to other rules, including those pertaining to deviations. Below, I address the following key proposals:[3]

---

[2] *Calpine Corp. v. PJM Interconnection, L.L.C.*, 169 FERC ¶ 61,239 (2019) ("December 2019 Order"), *order on reh'g & clarification*, 171 FERC ¶ 61,035, *order on compliance*, 173 FERC ¶ 61,061 (2020), *order on compliance & clarification*, 174 FERC ¶ 61,036, *order setting aside prior order, in part*, 174 FERC 61,109 (2021).

[3] Terms not otherwise defined herein shall have the same meaning as set forth in the Tariff and/or Operating Agreement. The Tariff and Operating Agreement are currently located under PJM's "Intra-PJM Tariffs" eTariff title, available here: https://etariff.ferc.gov/TariffBrowser.aspx?tid=1731.

- **Use of Tracking Ramp Limited Desired ("TRLD") MW ("megawatt") (power) and TRLD MWh ("megawatt-hour") (energy) metrics (together "TRLD")** as set forth in proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1): Through a step-by-step explanation of the proposed Tariff changes, I discuss how replacing Real-time Desired MW ("RT Desired MW") metrics with TRLD for purposes of calculating real-time energy make whole payments and deviation charges provides a more complete picture of how closely to PJM's expectations a resource is operating in the Real-time market[4] across multiple, consecutive five-minute increments of the resource's commitment period (Part II of my affidavit, below);

- **Implementation of the proposed balancing Energy Make Whole credit equation**, as set forth in proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2): I explain how PJM's proposed balancing Energy Make Whole credit eligibility rules will work in tandem with the proposed TRLD MWh metric and proposed balancing Energy Make Whole credit equation to provide a more transparent, intuitive, and complete representation of the financial impacts of following and deviating from PJM's commitment and dispatch instructions (Part III of my affidavit, below); and

- **Clarifications to the rules that determine when a resource is considered eligible for real-time energy make whole payments**, as set forth in proposed Tariff, Attachment K-Appendix, section 3.2.3(e)(i): I will demonstrate, through several examples, how the proposed TRLD MWh metric, balancing Energy Make Whole credit equation, and eligibility rules will work together to clearly demonstrate, in a more transparent manner, the impact of generation resources following and/or deviating from PJM's expectations in the Real-time Energy Market (Parts IV and V of my affidavit, below).

8. In addition, I have appended one exhibit to my affidavit, Exhibit No. Morelli-0001. Exhibit No. Morelli-0001 contains the calculations in each step of the proposed balancing Energy Make Whole credit equation for a hypothetical resource. I walk through the calculations in Part III of my affidavit, below.

[4] PJM's Market Settlement Reporting System will provide stakeholders with the results of PJM's calculations of real-time energy make whole payments based on the TRLD MWh metric and Actual MWh.

II. THE TRLD METRIC

9. In this part of my affidavit, I explain the equations underlying the new proposed TRLD MW (power) and TRLD MWh (energy) metrics, as set forth in proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1).

10. PJM is proposing to use TRLD MWh (energy) to calculate "balancing Energy Make Whole credits and generator deviation charges as a representation of the level at which the resource would be desired if operating as requested by [PJM]."[5] My affidavit on this topic is organized as follows:

- In section II.A, below, I will define and provide a brief overview of TRLD.

- In section II.B, I will describe how PJM proposes to calculate TRLD MW (power). The relevant equations for deriving the TRLD MW metric are set forth in proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(i). Different equations apply depending on whether the Real-time Settlement Interval is at start time (t_0) or after. I provide a step-by-step explanation of how TRLD MW (power), by default an adjusted metric, is calculated.

- In section II.C of my affidavit, below, I will provide a step-by-step description of how the unadjusted TRLD MW metric, as described in proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(ii) is calculated (section III.C of my affidavit, below). Different equations apply depending on whether the Real-time Settlement Interval is at start time (t_0) or after.

- In section II.D, I will explain when during a resource's dispatch in an Operating Day PJM will stop calculating TRLD MW and unadjusted TRLD MW for that resource, as well as explain the equations used at the end time of the TRLD MW and unadjusted TRLD MW calculation, which may vary depending on the circumstances. This is set forth in proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(iii).

- In section II.E of my affidavit, below, I will explain how to calculate TRLD MWh (energy), as described in proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(iv). TRLD MWh (energy) is the metric used to determine

[5] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1).

a resource's balancing Energy Make Whole credits and generator deviation charges.

- In section II.F, I will explain a catch-all provision that refers to additional adjustments that may apply to both TRLD and unadjusted TRLD, as described in proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(v).

- In section II.G, I will summarize all of the adjustments to TRLD and unadjusted TRLD.

A. TRLD MW (power) and TRLD MWh (energy)

11. PJM is proposing to use the TRLD MWh metric to calculate balancing Energy Make Whole credits and generation deviation charges, and to make conforming changes to other rules where applicable (e.g., Reactive Power Make Whole credits).

12. TRLD MWh represents the "level at which the resource would be desired if operating as requested by [PJM],"[6] or, in other words, the energy (MWh) output PJM expects from a resource in a particular Real-time Settlement Interval based on the assumption that the resource has been operating as PJM expected over the resource's commitment period across all of the Real-time Settlement Intervals. A resource's TRLD MWh value in a given Real-time Settlement Interval is "the expected energy produced between the start of the Real-time Settlement Interval and the end of the Real-time Settlement Interval based on the . . . [TRLD MW] (power) at the start and at the end of the Real-time Settlement Interval and the resource's ramping capability[.]"[7] TRLD MW is a power metric. The average of the TRLD MW values at the start and at the end of a Real-time Settlement Interval make up the energy metric, TRLD MWh, but for fast-ramping resources that do not require the full five minutes of a Real-time Settlement Interval to ramp to the next desired MW point, TRLD MWh will recognize that the resource will reach the desired MW point prior to the end of the interval.[8]

13. In broad terms, power (MW) is the rate at which energy is produced or used, whereas energy (MWh) is the power used over time. For example, if Resource 1

[6] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1).

[7] *Id.* section 3.2.3(e-1)(iv).

[8] For example, if a resource is directed to be at 100 at 9:00 and at 120 at 9:05, it is possible the resource could ramp like this: 9:00 – 100 MW; 9:01 – 110MW; 9:02 – 120 MW; 9:03 – 120 MW; and 9:04 – 120 MW.

produces power at a rate of 50 MW steadily over 60 minutes, while Resource 2 simultaneously produces 60 MW for 30 minutes, then 40 MW for 30 minutes, the two resources will have produced different amounts of power (MW) but the same amount of energy (MWh) in that hour:

	Power (MW)	**Energy (MWh)**
Resource 1	50 MW for 60 min	50 MWh
Resource 2	60 MW for 30 min, 40 MW for 30 min	50 MWh

14. PJM dispatches the system in power terms, but settles market activity in energy terms. Therefore, it is necessary to convert the expectations of how a resource operates from power terms to energy terms before comparing the resource's actual output, which is measured in energy, to the expected output.

B. TRLD MW (power) Calculations at t_0 and After t_0

15. TRLD MW is an "adjusted metric."[9] Thus, when the Tariff refers to TRLD MW, it should be assumed that any necessary adjustments have been applied to the metric.[10] In this section of my affidavit, I will describe how TRLD MW is derived and the various adjustments that may need to be made to the metric. The equation for calculating TRLD MW is set forth in proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(i). The potential adjustments to the metric are set forth in proposed Tariff, Attachment K-Appendix, sections 3.2.3(e-1)(i) and 3.2.3(e-1)(v).

16. The first step in calculating TRLD MW (power) is to determine whether the Real-time Settlement Interval in question is equal to t_0, which is the first Real-time Settlement Interval in which TRLD MW will be calculated for a resource each time it comes online. The TRLD MW start interval t_0 will not always be the same as the first Real-time Settlement Interval of a resource's pool-scheduled commitment period. As defined in the proposed Tariff, t_0 is "when a generation resource is first expected by [PJM] to be online or when a generation resource is dispatchable, while honoring soak time differences[.]"[11] Thus, the first Real-time Settlement Interval

[9] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(i).

[10] In the limited circumstances when the unadjusted TRLD MW is used, the Tariff refers specifically to the "unadjusted TRLD MW" metric.

[11] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(i).

in the TRLD MW calculation, t_0, may occur before or after the start of the resource's pool-scheduled commitment period. For example, if the Market Seller has communicated to PJM that the resource will be self-scheduled before the start of the resource's pool-scheduled commitment period, PJM would expect the resource to be online before the start of the resource's pool-scheduled commitment. In this case, t_0 would begin before the resource's pool-scheduled commitment start time. Even though self-scheduled resources are not eligible for balancing Energy Make Whole payments, it is still necessary to calculate TRLD MW when a resource is self-scheduled, because TRLD MW is also used to calculate deviation charges.

1. TRLD MW in Real-time Settlement Interval t_0

17. The equation for deriving TRLD MW applicable to Real-time Settlement Interval t_0 differs from the TRLD MW equation in subsequent intervals. If the Real-time Settlement Interval is equal to t_0, the next step is to determine if the resource has a soak process. A "soak process" refers to a period when the resource is online but not yet fully operational. A resource with a soak process needs to run for a certain period of time, usually at its Economic Minimum, before it is dispatchable. Nuclear, steam, and combined cycle resources typically have a soak process.[12] On the other hand, engines, combustion turbines, Intermittent Resources, and Energy Storage Resources typically do not have a soak process.[13]

18. The TRLD MW value of a resource that "does not have a soak process and is directed to come online as soon as possible" in Real-time Settlement Interval t_0 is 0 MW;[14] t_0 for this resource is the earlier of: a) when the notification to come online is made plus the resource's startup and notification time; and b) when the unit comes online. PJM expects these resources to be at 0 MW and subsequently start ramping from the first interval such resources are dispatched.

19. Otherwise, for resources with a soak process, regardless of whether they are expected to start immediately or at a time in the future, as well as for resources without a soak process that are expected to initiate their startup and notification process at a future point in time, the TRLD MW value in Real-time Settlement Interval t_0 is:

[12] Tariff, Definitions R-S (Start-up Costs).

[13] *Id.*

[14] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(i).

= Max [Min (LMP Desired MW, Dispatch MW), Tracking Desired Economic Minimum][15]

20. For these resources, PJM expects the resource to be at Economic Minimum MW and able to follow dispatch at a future specified time, t_0. However, the calculation also recognizes that a resource could be at a higher MW output than Economic Minimum at time t_0 and makes allowances for that as long as it is consistent with dispatch instructions and/or the economics for that interval. "LMP Desired MW" is "the generation resource's expected output level based on its Final Offer at the Real-time Locational Marginal Price [("LMP")] from the dispatch run at the applicable pricing point."[16] In other words, LMP Desired MW is the expected MW output based on what the generation resource represented it could produce at the price level in its offer and the maximum point at which it is economic for the resource to produce MW in that interval.

21. "Dispatch MW" means the "energy dispatch signal MW from the dispatch run."[17] In other words, Dispatch MW is the amount PJM instructs the generation resource to produce.

22. Unless certain conditions trigger an adjustment, Tracking Desired Economic Minimum is "the generation resource's minimum operating limit,"[18] which is the resource's Economic Minimum unless PJM "has declared Minimum Generation Emergency conditions, in which case it shall be the emergency minimum."[19] However, "[i]f the resource's minimum operating limit increases by more than 5% of the resource's minimum operating limit at the time of commitment, the minimum operating limit at the time of commitment will be used."[20] Using the original operating limit at the time of the commitment effectively holds a resource accountable for making the resource less flexible after the commitment decision has been made. The 5% allowance permits small ambient temperature adjustments before holding the resource accountable to the Economic Minimum offered at the time of commitment.

---

[15] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(i).

[16] *Id.*

[17] *Id.*

[18] *Id.*

[19] *Id.* section 3.2.3(e-1).

[20] *Id.* section 3.2.3(e-1)(i).

23. Under certain conditions, the Tracking Desired Economic Minimum value used to calculate TRLD MW may require adjustment. Namely, if a resource is manually directed by PJM dispatchers to increase output and produce no less than a given MW value due to a transmission constraint or other reliability issue, Tracking Desired Economic Minimum is adjusted to "the lower limit from the manual dispatch instruction as directed by [PJM]."[21]

24. Thus, to determine the TRLD MW value in Real-time Settlement Interval t_0 for resources with a soak process and/or resources that have not been directed to come online as soon as possible, PJM will take the smaller of the LMP Desired MW and Dispatch MW values, then compare the resulting value against Tracking Desired Economic Minimum, then take the larger of those two values. The resulting value is the TRLD MW value in Real-time Settlement Interval t_0.

25. First, as the above equation illustrates, TRLD MW may be no lower than the Tracking Desired Economic Minimum, which is the resource's "minimum operating limit" unless certain conditions apply that require an adjustment. This is because PJM expects resources with a soak process, or those that are committed for a future point in time to be online and operating at no less than Economic Minimum and able to follow dispatch at t_0. Second, Tracking Desired Economic Minimum will be compared to the lower of PJM's dispatch instructions or where the resource is expected to be based on LMPs without accounting for ramp rate limitations. This makes an allowance for the resource to be operating above Economic Minimum at t_0 as long as doing so is consistent with dispatch instructions and/or the economics, or LMP, for that interval. Thus, TRLD MW is typically floored at Economic Minimum and limited to the lower of the MW output values from PJM's dispatch run.

2. TRLD MW in Real-time Settlement Intervals After t_0

26. For each Real-time Settlement Interval after the resource's initial start time t_0, TRLD MW for Real-time Settlement Interval t:

$$= TRLD\ MW_{t-1} \pm Ramp_t$$

27. In the above equation, "t" is the start time of the Real-time Settlement Interval for which TRLD MW is being calculated, and represents any Real-time Settlement

[21] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(i).

Interval subsequent to t_0.[22] TRLD MW_{t-1} is therefore the TRLD MW value at the start of the Real-time Settlement Interval directly preceding the Real-time Settlement Interval for which TRLD MW is being calculated. "Ramp" is the "[i]ncrease or decrease in MW calculated using the Real-time [LMP] from the dispatch run at the applicable pricing point, the resource's Final Offer, and the ramp rate parameters. The increase or decrease in MW is restricted by the most limiting parameter among the ramp rate, the Tracking Desired Economic Minimum, and the Tracking Desired Economic Maximum[.]"[23] $Ramp_t$ is Ramp, or the increase or decrease in MW, from t-1 to t.

28. $Ramp_t$ is restricted by the most limiting of the three following parameters:

- the resource's ramp rate, i.e., how quickly the resource can increase or decrease its power output;
- Tracking Desired Economic Minimum, which, as defined and explained above, is the resource's Economic Minimum unless certain conditions apply that require the parameter to be adjusted; and
- Tracking Desired Economic Maximum.

29. Tracking Desired Economic Maximum is "the generation resource's maximum operating limit,"[24] i.e., the resource's "Economic Maximum unless [PJM] has declared Maximum Emergency conditions, in which case it shall be the emergency maximum."[25] However, "[i]f a resource's maximum operating limit decreases by more than 5% of the resource's maximum operating limit at the time of commitment, the maximum operating limit at the time of commitment will be used."[26] Using the original operating limit at the time of the commitment effectively holds a resource accountable for making the resource less flexible after the commitment decision has been made. The 5% allowance permits small ambient temperature adjustments before holding the resource accountable to the Economic Maximum offered at the time of commitment.

[22] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(i).

[23] *Id.*

[24] *Id.*

[25] *Id.* section 3.2.3(e-1).

[26] *Id.* section 3.2.3(e-1)(i).

30. Tracking Desired Economic Maximum may need to be adjusted if "due to a transmission constraint or other reliability issue" the resource is manually directed by PJM dispatchers to decrease output and produce no more than a given MW value.[27] In this case, the Tracking Desired Economic Maximum is the "the upper limit from the manual dispatch instruction as directed by [PJM]."[28]

31. Thus, for each of the Real-time Settlement Intervals following the start (t_0) until the resource is released, TRLD MW is equal to the TRLD MW at the beginning of the directly preceding interval (t-1) plus or minus the increase or decrease in output from t-1 to t (i.e., $Ramp_t$), as restricted by the most limiting of the three parameters described above, with any necessary adjustments to Tracking Desired Economic Minimum and Tracking Desired Economic Maximum, and, if needed, two additional adjustments described in sections III.B.iii and III.F, below.[29]

32. The following are two examples of what it means to restrict $Ramp_t$ by the most limiting of the three parameters. Assume that a hypothetical resource's TRLD MW is 50 MW at t-1. The resource has a ramp rate of 1 MW/min, an Economic Minimum of 40 MW, and an Economic Maximum of 75 MW. LMP from the dispatch run indicates it is economic for the resource to be producing energy at 80 MW based on the resource's incremental energy offer, or 5 MW above Economic Maximum.

33. In my first example, the resource is economic to move 30 MW, from the TRLD MW at t-1 of 50 MW up to 80 MW, but the resource's Economic Maximum of 75 MW would limit the movement to 25 MW. The ramp rate of 1 MW/min means that the resource can only move 5 MW in the next five-minute interval. The Economic Minimum of 40 MW is not a limiting parameter in this example.

34. $Ramp_t$ is limited by the most limiting of the three parameters. In this example, the resource's $Ramp_t$ is therefore limited to the lesser of how far the resource can move based on the resource's ramp rate of 1 MW/min, i.e., 5 MW, and how far it can move based on its Economic Maximum of 75 MW, i.e., 25 MW. Thus, $Ramp_t$ is 5 MW.

[27] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(i).

[28] *Id.*

[29] *Id.*

35. In my second example, based on the same hypothetical resource, TRLD at t-1 is 72 MW. All the other elements of the example remain the same. The resource is economic to move up 8 MW to the LMP Desired MW of 80 MW. However, the 8 MW movement is restricted by the most limiting of the three parameters. Once again, the Economic Minimum of 40 MW is not a limiting parameter. The resource's Economic Maximum of 75 MW would limit the resource's movement to 3 MW. The ramp rate of 1 MW/min would limit the resource's movement to 5 MW. Thus, in this second example, $Ramp_t$ is 3 MW.

3. Further Adjustment to TRLD MW

36. In addition to adjustments to the Tracking Desired Economic Minimum and Tracking Desired Economic Maximum inputs to the TRLD MW equations in order to account for manual dispatch instructions, TRLD MW may also be further adjusted "if the resource has a regulation or reserve assignment and is unable to provide such assignment while generating the initial [TRLD] MW due to the resource's applicable operating parameters."[30] TRLD MW may be adjusted up or down to accommodate the regulation or reserve assignment. For example, if a resource has a 10 MW regulation assignment and an Economic Maximum of 100 MW, the total energy output that the resource can actually produce in response to dispatch instructions is limited to 90 MW since it must have 10 MW of bandwidth to move up and down to provide regulation service. Therefore, in this example, if the TRLD MW that is initially calculated is above 90 MW, TRLD MW would be adjusted down to 90 MW.

37. Additionally, when calculating the TRLD MW for the next interval, the adjusted TRLD MW metric is used as the TRLD MW value from which the resource will be expected to ramp.[31] This rule helps to prevent PJM from expecting a resource to perform in a way that is not possible based on expectations from the prior interval and characteristics of the resource such as ramp rate.

38. A catch-all provision addresses additional, potential adjustments to both adjusted and unadjusted TRLD MW and TRLD MWh, which I will explain in section II.F of my affidavit, below.

[30] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(i).

[31] *Id.*

C. Unadjusted TRLD MW (power) Metric Calculations at t_0 and After t_0

39. An unadjusted TRLD MW metric is less commonly used. This unadjusted TRLD MW provides the reference point to determine at what MW level the resource would have been economically expected to operate absent any regulation or reserve assignment or manual dispatch instruction that may have been given. This unadjusted TRLD MW value becomes relevant only when calculating the opportunity costs included in Other Market Revenue and Opportunity Cost Owed in Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2)(i). Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(ii) sets forth the equations for deriving unadjusted TRLD MW. Despite being referred to as the unadjusted TRLD MW metric, catch-all adjustments set forth in proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(v) may apply as further discussed in paragraph 57 below.

1. Unadjusted TRLD MW in Real-time Settlement Interval t_0

40. For the Real-time Settlement Interval equal to t_0, the unadjusted TRLD MW equals the adjusted TRLD MW as described in section II.B(i) above while excluding the impact of regulation and reserve assignments or manual dispatch instructions.

2. Unadjusted TRLD MW in Real-time Settlement Intervals After t_0

41. For each Real-time Settlement Interval after the start time, t_0, the unadjusted TRLD MW is calculated in the same fashion as the adjusted TRLD MW, with the exception that it excludes any adjustments. The Unadjusted TRLD MW is:

$$= unadjusted\ TRLD\ MW_{t-1} \pm Ramp_t$$

42. In the above equation, "t" is the start time of the Real-time Settlement Interval for which the unadjusted TRLD MW is being calculated.[32] Unadjusted TRLD MW_{t-1} is therefore the unadjusted TRLD MW value at the start of the Real-time Settlement Interval directly preceding the Real-time Settlement Interval for which the unadjusted TRLD MW is being calculated.

43. "Ramp" is the "[i]ncrease or decrease in MW calculated using the Real-time [LMP] from the dispatch run at the applicable pricing point, the resource's Final Offer, and the ramp rate parameters. The increase or decrease in MW is restricted by the most limiting parameter among the ramp rate, the [E]conomic [M]inimum, and the

[32] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(i).

unadjusted [E]conomic [M]aximum [.]"[33] That is, Ramp is calculated in the same fashion as in the adjusted TRLD MW calculation, except the unadjusted Economic Minimum and unadjusted Economic Maximum values are used instead.

44. The "unadjusted Economic Minimum" is the resource's "minimum operating limit" i.e. the resource's Economic Minimum unless PJM "has declared Minimum Generation Emergency conditions, in which case it shall be the emergency minimum."[34] However, "if the resource's minimum operating limit increases by more than 5% of the resource's minimum operating limit at the time of commitment, the minimum operating limit at the time of commitment will be used." Any manual direction by PJM dispatchers to increase output and produce no less than a given MW value due to a transmission constraint or other reliability issue is not factored in the unadjusted Economic Minimum so that PJM can determine where the resource would have been desired based on economics.

45. Similarly, the "unadjusted Economic Maximum" is the resource's "maximum operating limit," i.e., the resource's Economic Maximum unless PJM "has declared Maximum Emergency conditions, in which case it shall be the emergency maximum."[35] However, "if a resource's maximum operating limit decreases by more than 5% of the resource's maximum operating limit at the time of commitment, the maximum operating limit at the time of commitment will be used."[36] Any manual direction by PJM dispatchers to decrease output and produce no more than a given MW value due to a transmission constraint or other reliability issue is not factored in the unadjusted Economic Maximum so that PJM can determine where the resource would have been desired based on economics.

46. Ramp is thus restricted by the most limiting of the three following parameters: (1) ramp rate; (2) unadjusted Economic Minimum; and (3) unadjusted Economic Maximum. That is, this equation mirrors the ramp equation for the adjusted TRLD MW, except it uses the unadjusted Economic Minimum and unadjusted Economic Maximum values.

---

[33] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(ii).

[34] *Id.* section 3.2.3(e-1).

[35] *Id.*

[36] *Id.* section 3.2.3(e-1)(i).

47. If the resource has a regulation or reserve assignment, it is ignored in the calculation of Unadjusted TRLD MW.

D. TRLD MW (power) and Unadjusted TRLD MW (power) Calculations End Time

48. The rules set forth how long the TRLD MW and unadjusted TRLD MW equations, in proposed Tariff, Attachment K-Appendix, sections 3.2.3(e-1)(i) and 3.2.3(e-1)(ii), will be applied to a resource's Real-time Settlement Intervals.

49. PJM will calculate TRLD MW and unadjusted TRLD MW based on the equations set forth in proposed Tariff, Attachment K-Appendix, sections 3.2.3(e-1)(i) and 3.2.3(e-1)(ii) "until the resource goes offline[,]" with one exception.[37]

50. The exception is that if a generation resource fails to follow PJM's instructions (i.e., trips or is taken offline at the Market Seller's request) in Real-time Settlement Intervals "prior to the later of the end of the Day-ahead Energy Market commitment or the end of the Minimum Run Time[.]"[38] PJM will continue to apply the TRLD MW and unadjusted TRLD MW equations to Real-time Settlement Intervals "until the later of the end of the Day-ahead Energy Market commitment or the end of the Minimum Run Time."[39] This allows PJM to establish where the resource would have been desired had it continued to operate consistent with the initial commitment expectation so that this output level can be taken into account when calculating the costs and revenues that would have been incurred in Step 1 of the balancing Energy Make Whole equation as detailed in Tariff, Attachment K-Appendix, section 3.2.3(e-2)(i).

51. A different equation will be used to calculate TRLD MW and unadjusted TRLD MW in the Real-time Settlement Intervals after PJM releases a generation resource to come offline, where the resource follows PJM's instructions to come offline. In this case, the TRLD MW is incrementally ramped down to its minimum output, irrespective of the real-time LMP. The unadjusted TRLD MW will equal the adjusted TRLD MW in these Real-time Settlement Intervals with one exception, which I will address further, below. In most cases, the equation is[40]:

---

[37] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(iii).

[38] *Id.*

[39] *Id.*

[40] *Id.*

Max(TRLD MW_{t-1} – Down $Ramp_t$, Tracking Desired Economic $Minimum_t$)

Where

Down Ramp = Decrease in MW utilizing the resource's down ramp rate parameter.

Note that the equation does not ramp the unit below its Tracking Desired Economic Minimum value even though it is expected that the resource will eventually ramp below Economic Minimum all the way to zero MW. However, this expectation will be recognized in the TRLD MWh metric which is discussed further below, and which is the value that is actually used in the balancing Energy Make Whole credit and deviation charge calculations.

52. The one exception is that the above equation that ramps a unit down to Economic Minimum will not apply to unadjusted TRLD MW if the resource has been manually dispatched offline.[41] In that case, the unadjusted TRLD MW calculation will continue to apply the equation set forth in proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(ii) "until the manual dispatch instruction ends." [42] This allows PJM to establish where the resource would have been desired based on economics had it continued to operate consistent with the initial commitment expectation so that this output level can be taken into account when calculating the opportunity costs associated with being directed offline.

E. TRLD MWh (energy) Calculations

53. The proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(iv) sets forth how the TRLD MW and unadjusted TRLD MW power metrics are converted into the energy metrics that are actually used in calculating make whole credits and deviation charges. This section sets forth the applicable energy metrics for the Real-time Settlement Interval prior to start time t_0, after PJM releases a resource to come offline, and in all other Real-time Settlement Intervals.

54. First, before start time t_0, the resource's Actual MWh[43] will be used in place of TRLD MWh and unadjusted TRLD MWh in Step 1 of the equation "[f]or all Real-

[41] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(iii).

[42] *Id.*

[43] Actual MWh is a new defined term in proposed Tariff, Definitions A – B, in accordance with Tariff, Attachment K-Appendix, section 3.1A.

time Settlement Intervals prior to the start time of [TRLD MW] calculation, t_0[.]"[44] Actual MWh is appropriate, because the resource is typically ramping up during this period and may not be following a linear ramp rate.[45]

55. Second, after PJM releases the generation resource to come offline, if the resource's Actual MWh is below Economic Minimum, the resource's Actual MWh will be used in place of TRLD MWh and unadjusted TRLD MWh in Step 1 of the equation. Once operating below Economic Minimum, a resource's ramp rate down to zero may not be linear. Using the resource's actual output in this operating range ensures the resource is not assessed deviations and will be made whole to its actual output for these intervals as long as PJM is actually expecting the resource to ramp offline.

56. Third, in all other Real-time Settlement Intervals, TRLD MWh will generally be the average of the adjusted or unadjusted TRLD MW at the start and end of each Real-time Settlement Interval. TRLD MWh will equal "the expected energy produced between the start of the Real-time Settlement Interval and the end of the Real-time Settlement Interval based on the [TRLD MW] at the start and at the end of the Real-time Settlement Interval and the resource's ramping capability, as further described in the PJM Manuals."[46] The unadjusted TRLD MWh will equal "the expected energy produced between the start of the Real-time Settlement Interval and the end of the Real-Time Settlement Interval based on the unadjusted [TRLD MW] at the start and at the end of the Real-time Settlement Interval and the resource's ramping capability, as further described in the PJM Manuals."[47]

F. Catch-All Provision

57. Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(v) is a catch-all provision that captures additional adjustments that may apply to adjusted and unadjusted TRLD MW and TRLD MWh. The broadly applicable proposed provision is necessary "to account for instances where [PJM] is unable to dispatch the system using the real-time security constrained economic dispatch system and/or where the real-time security-constrained economic dispatch application is providing dispatch signals inconsistent with the resource's offer data, or other

[44] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(iv).

[45] In addition, proposed Tariff, Attachment K-Appendix, sections 3.2.3(e-2)(i) and 3.2.3(e-2)(ii) limit a no soak resource's real-time energy make whole payment to Economic Minimum.

[46] *Id.* section 3.2.3(e-1)(iv).

[47] *Id.*

abnormal dispatch scenarios."[48] This allows the TRLD MW and MWh values to be adjusted to match PJM's expectations in these abnormal operating conditions.

G. Summary of Potential Adjustments

58. In summary, the following conditions may call for adjustments to TRLD:

- Tracking Desired Economic Minimum may be adjusted if a resource is requested to increase output "due to a transmission constraint or other reliability issue;"

- Tracking Desired Economic Maximum may be adjusted if a resource is requested to decrease output "due to a transmission constraint or other reliability issue;" and

- TRLD MW may be adjusted "if the resource has a regulation or reserve assignment and is unable to provide such assignment while generating the initially calculated [TRLD] MW due to the resource's applicable operating parameters."[49]

Additionally, if a resource clamps its Economic Minimum or Economic Maximum, an adjustment is included in both the adjusted and unadjusted TRLD. Additional adjustments necessary to respond to abnormal dispatch scenarios may also apply to adjusted and unadjusted TRLD.

III. BALANCING ENERGY MAKE WHOLE CREDIT EQUATION

59. PJM is proposing to revise the terminology used to refer to real-time energy make whole payments. Under the revised Tariff, balancing Operating Reserve credits are called balancing Energy Make Whole credits. In addition to a change in terminology, PJM is also proposing to replace the status quo balancing Operating Reserves credit equation that is presently used to calculate real-time energy make whole payments or credits with a three-step balancing Energy Make Whole credit equation.

60. If adopted, the proposed balancing Energy Make Whole credit equation will make a generation resource whole to its costs while also limiting the real -time energy

[48] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(v).

[49] *Id.* section 3.2.3(e-1)(i).

make whole credits to the amount the resource would have been entitled to had it operated as PJM expected in the Real-time Energy Market, as determined using the proposed TRLD MWh metric. Under the proposed three-step equation, assumed revenues that the resource would not have been able to attain, even if it had followed dispatch, are not included.

61. This section of my affidavit is organized in the following manner:

- In section III.A, below, I provide an overview of the status quo balancing Operating Reserve credit equation.
- In section III.B., below, I provide an overview of the proposed balancing Energy Make Whole credit equation.
- In section III.C., I describe Exhibit No. Morelli-0001 broadly, in the context of the proposed, three-step balancing Energy Make Whole credit equation.
- Next, in section III.D, I explain how Step 1 values are calculated for the hypothetical generation resource described in Exhibit No. Morelli-0001. First, I walk through the Step 1 calculation to derive the Tracking Balancing Net Revenue for each of the resource's two Real-time Settlement Intervals. Then, I determine the Tracking Balancing Energy Make Whole Credit for the Segment.
- In section III.E, I explain how Step 2 values are calculated in each of the resource's two Real-time Settlement Intervals. First, I walk through the Step 2 calculation to derive the Actual Balancing Net Revenue for each of the resource's two Real-time Settlement Intervals. Then, I determine the Actual Balancing Energy Make Whole Credit for the Segment.
- In section III.F, I explain Step 3, which determines the final real-time energy make whole credit paid to a resource in each Segment of the resource's Operating Day.

A. Status Quo Balancing Operating Reserve Credit Equation

62. Below, I set forth a simplified version of the status quo balancing Operating Reserve credit equation, with the Cost side of the equation color-coded in green, and the Value (i.e., resource revenues) side of the equation color-coded in blue:

balancing Operating Reserve Credits = Max(Cost @ RT MW Used – Value @ Balancing Value MW Used), 0.

Broken down further, the simplified representation of the status quo equation is:

*balancing Operating Reserve Credits = Max [{Sum of (Min(RT Desired MW, RT MW) * $/MWh Offer – [(Max (Min (DA MW, Max(RT Dispatch Desired MW, Original Schedule Desired MW using Committed Offer)), RT MW) – DA MW) * RT LMP + Net Ancillary Services Profits and Other Revenues)) across all intervals in the Segment + DA Revenue + DA Energy Uplift Credit]}, 0]*

63. Continuing with the convention of representing Cost in green and Value in blue, the inputs to the respective Cost and Value sides of this equation are explained further, below.

1. Cost component (status quo)

64. Under the status quo rules, Cost is equal to the cost of the Real-time MW ("RT MW") actually produced by the resource multiplied by the resource's $/MWh offer, unless the resource has produced more than 110% of the Desired MW in which case the cost is equal to the Desired MW multiplied by the resource's $/MWh offer. Start-Up, No Load, and incremental costs are components of the Real-time $/MWh Offer. A simplified representation of the status quo Cost component is[50]:

***Cost** = **RT MW Used** * $/MWh Offer*

Where

*If RT MW > 110% of RT Desired MW, **then RT MW Used** = RT Desired MW;*

*Else, **RT MW Used** = RT MW*

65. If a resource has produced more MW than 110% of the MW desired by PJM (that is, the resource is over-generating and deemed to be not following dispatch), PJM

[50] *PJM Manual 28: Operating Agreement Accounting*, PJM Interconnection, L.L.C., § 5.2.1 (Oct. 1, 2025), https://www.pjm.com/-/media/DotCom/documents/manuals/m28.pdf ("PJM Manual 28") ("PJM calculates the resource's five minute interval real-time energy offer amount based on its applicable schedule's offer data, where the applicable schedule's offer is lesser of the Committed Offer and the Final Offer, and its Real-time MW for that five minute interval. **However, for any five minute interval where the resource's Real-time MW is greater than 110% of its Operating Reserve Desired MW, Operating Reserve Desired MW is used to determine the five minute interval real-time energy offer amount.** If PJM declares a Realtime Market Suspension, the Real-time MW is used to determine the five minute interval real-time energy offer amount." (emphasis added)).

will only make the resource whole for the cost of RT Desired MW, since PJM did not direct the resource to produce the additional MW above RT Desired MW. This incentivizes resources to follow dispatch, because cost recovery for the excess MW is not guaranteed. Conversely, if a resource produces fewer MW than RT Desired MW, the resource will only be made whole for what it actually produced, since the resource did not actually incur the costs of the full Ddesired MW amount.

2. Value component (status quo)

66. Value represents a resource's revenues from the Real-time and Day-ahead Energy Markets and Ancillary Services Markets. A simplified representation of the status quo Value component is:

***Value** = **Balancing Revenue** + DA Revenue + DA Energy Make Whole Credit + Net Ancillary Services Profits and Other Revenues*

where

***Balancing Revenue** = (**Balancing Revenue MW Used**– DA MW) * RT LMP*

where

***Balancing Revenue MW Used** = Max (Min (DA MW, **RT Desired MW**), RT MW)*

where

***RT Desired MW** = Max(RT Dispatch Desired MW, Original Schedule Desired MW using Committed Offer)*

67. Because any MW scheduled in the Day-ahead Energy Market is already settled at day-ahead prices, only the difference between the RT MW and Day-ahead MW ("DA MW") is compensated at real-time prices. Real-time Energy Market revenues are thus balancing revenues equal to the difference between the RT MW and DA MW values, multiplied by the RT LMP. Thus, the Real-time Energy Market revenues, i.e., balancing revenues, to be included on the Value side of the balancing Operating Reserve Credit equation is:

*Balancing Revenue = (Balancing Revenue MW Used – DA MW) * RT LMP*

68. However, the MW used to calculate balancing revenues is not simply equal to actual RT MW output minus the DA MW. The Value side relies on the Balancing Revenue MW Used, which is the greater of actual RT MW output and RT Desired MW, assuming the resource has no day-ahead commitment. Taking the greater of the two values incentivizes resources to follow dispatch and minimizes make whole payments to resources deviating from PJM's dispatch instructions. Thus:

Balancing Revenue MW Used = Max (Min (DA MW, RT Desired MW), RT MW)

where

RT Desired MW = Max(RT Dispatch Desired MW, Original Schedule Desired MW using Committed Offer)

69. However, when a resource has a day-ahead commitment, the day-ahead committed MW also needs to be considered in the Balancing Value MW Used as well. More specifically, as represented in the equations, above, to determine the RT MW used to calculate revenue from the Real-time Energy Market, PJM first identifies the lesser of the DA MW committed and RT Desired MW.[51] The lesser of those two figures is then compared to RT MW, and the greater of those two figures is then used to determine the revenue that a resource receives from the Real-time Energy Market.[52] The MW value resulting from this calculation is called the Balancing Revenue MW Used.

70. Balancing Revenue MW Used has the effect of maximizing the revenue that can be used to offset any costs, reducing uplift when a resource over-generates (a form of not following dispatch). Similarly, when a resource generates below the desired MW (another form of not following dispatch), it excludes any negative revenue that results from buying out from the resource's DA energy position beyond what was needed to follow PJM's dispatch instructions, thus reducing make whole credits and shifting the cost responsibility for such negative revenue (which is essentially a cost) to the resource.

[51] Tariff, Attachment K-Appendix, section 3.2.3(e) as further elaborated upon in PJM Manual 28, section 5.2.1.

[52] *Id.*

3. RT MW values in Cost and Value components (status quo)

71. Under the status quo balancing Operating Reserve credits equation, when resources deviate from PJM's real-time dispatch instructions, the RT MW reflected in the Cost and Value sides of the equation may differ, resulting in an apples-to-oranges comparison in the equation. The relevant RT MW inputs on the Cost and Value sides of the status quo equation are in red, below:

Cost = ***RT MW Used*** * *$/MWh Offer*

RT MW Used = *Min(RT Desired MW, RT MW)*

Value = ***Balancing Revenue*** + *DA Revenue + DA Energy Make Whole Credit + Net Ancillary Services Profits*

Balancing Revenue = (***Balancing Revenue MW Used*** – *DA MW) * RT LMP*

Balancing Revenue MW Used = *Max (Min (DA MW,* ***RT Desired MW****), RT MW)*

RT Desired MW = *Max(RT Dispatch Desired MW, Original Schedule Desired MW using Committed Offer)*

Thus, on the Cost and Value sides of the equation, the RT MW inputs are:

RT MW Used to derive Cost = *Min(RT Desired MW, RT MW)*

Balancing Revenue MW Used to derive Value = *Max (Min (DA MW, Max(RT Dispatch Desired MW, Original Schedule Desired MW using Committed Offer)), RT MW)*

72. As a result, the balancing Operating Reserves credit may include assumed revenues (Value) based on more RT MW than are reflected on the Cost side of the equation, particularly when resources deviate from PJM's dispatch instructions. Thus, under the current mechanism, the real-time energy output to which a resource should be made whole (Cost) and the real-time energy output for which the equation assumes the resource has been paid (Value) may differ. This can result in the existing balancing operating reserve credit calculation using revenues in excess of what the resource would have been able to attain even if it had followed dispatch when determining if the resource is owed a make whole credit.

B. The Proposed Balancing Energy Make Whole Credit Equation

73. As set forth in proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2), "[f]or generating resources, balancing Energy Make Whole credits received pursuant to this section shall be equal to the lesser of the Tracking Balancing Energy Make Whole Credit, as calculated in Step 1 below in Tariff, Attachment K-Appendix, section 3.2.3(e-2)(i), and the Actual Balancing Energy Make Whole Credit, as calculated in Step 2 below in Tariff, Attachment K-Appendix, section 3.2.3(e-2)(ii), for each Segment in the Operating Day[.]"

74. More specifically, the three steps in the proposed balancing Energy Make Whole credit equation are as follows:

- Step 1:
    - For each *Real-time Settlement Interval* in a Segment, calculate Tracking Balancing Net Revenue using TRLD MWh, which assumes the resource has performed as PJM expected in all Real-time Settlement Intervals in which the resource was eligible for make whole payments.[53]
    - For each *Segment* in an Operating Day, use the total Tracking Balancing Net Revenue across all Real-time Settlement Intervals in the Segment to determine the Tracking Balancing Energy Make Whole Credit.[54]
- Step 2:
    - For each *Real-time Settlement Interval* in a Segment, calculate Actual Balancing Net Revenue using Actual MWh, which reflects how the resource actually performed throughout the Real-time Settlement Intervals in which the resource was eligible for make whole payments.[55]
    - For each *Segment* in an Operating Day, use the total Actual Balancing Net Revenue across all Real-time Settlement Intervals in

[53] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2)(i).

[54] *Id.*

[55] *Id.* section 3.2.3(e-2)(ii).

the Segment to determine the Actual Balancing Energy Make Whole Credit.[56]

- Step 3:
    - For each *Segment* in the Operating Day, the total real-time energy make whole credit paid to a resource will be the lesser of the Tracking Balancing Energy Make Whole Credit, as calculated in Step 1, and the Actual Balancing Energy Make Whole Credit, as calculated in Step 2.[57]

75. A pool-scheduled generation resource's Operating Day consists of either one or two Segments, each comprised of blocks of five-minute, Real-time Settlement Intervals, for each time the resource cycles online.[58] With exception to proposed segmentation extension rules, discussed below, PJM is not proposing revisions to the status quo rules concerning how a resource's Operating Day is divided into Segments and Real-time Settlement Intervals.

76. In keeping with the status quo rules, PJM is proposing to apply the balancing Energy Make Whole credit equation to the eligible Real-time Settlement Intervals in each Segment of each pool-scheduled resource's Operating Day. The first segment of a resource's commitment in an Operating Day is equal to the greater of a resource's day-ahead schedule and the resource's Minimum Run Time.[59] No Load Costs are distributed across Real-time Settlement Intervals in the first and second Segments. Start-up Costs are distributed across intervals in the first Segment only and should thus be fully recovered in that Segment.

77. The second Segment, if applicable, is equal to any block of Real-time Settlement Intervals in which the resource operates at PJM's direction in excess of the greater of its day-ahead schedule and Minimum Run Time.[60] The one exception is if PJM releases the unit within 30 minutes of the end of its day-ahead schedule or Minimum Run Time. In this instance, PJM proposes to revise the eligibility rules to extend the first Segment, rather than beginning a second Segment, when a generation resource is released no more than 30 minutes beyond the end of the

[56] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2)(ii).

[57] *Id.* section 3.2.3(e-2).

[58] Tariff, Attachment K-Appendix, section 3.2.3(e).

[59] *Id.*

[60] *Id.*

resource's day-ahead commitment period or Minimum Run Time. Rather than triggering the start of the second Segment, under the proposed rule, PJM would consider this a late or staggered release, such that the additional Real-time Settlement Intervals would be included in the first Segment. This better acknowledges the fact that PJM dispatchers often have to stagger the release of units over the intervals preceding and following the top of the hour in order to avoid the sudden, large MW swings that could occur if many units simultaneously go offline at the top of the hour at the end of their day-ahead commitment. In these cases, the few extra intervals associated with a staggered release plan do not constitute a true extension of the resource's commitment and therefore appropriately belong within the first segment that covers the resource's day-ahead commitment and minimum run time.

78. If a generation resource is released *more* than 30 minutes beyond the end of the resource's day-ahead commitment period or Minimum Run Time, the status quo rules will continue to apply. An extension of more than 30 minutes will result a second Segment, which includes "any block of contiguous Real-time Settlement Intervals the resource runs under the direction of [PJM] in excess of the first Segment."[61]

79. Costs and revenues in different Real-time Settlement Intervals occurring in the same Segment can offset one another; however, offsets do not apply across Segments or across Operating Days.[62] That said, to the extent a resource is operating continuously across multiple Operating Days, the TRLD MWh and Actual MWh metrics will track the resource's MWh performance across days. In other words, while real-time make whole payments are only calculated and assessed by Segment within individual Operating Days, PJM recognizes that a resource may be committed and run across multiple Segments and Operating Days and makes the resource whole for those Segments and Operating Days individually. The proposed calculations continue this existing practice.

80. Each Real-time Settlement Interval is equal to five minutes. Thus, in each hour, there are 12 Real-time Settlement Intervals. Many of the inputs into the calculation are specified as hourly or dollar-per-MW-hour values, rather than five-minute

[61] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e)(ii).

[62] However, the proposed TRLD MWh metric measures a resources performance in accordance with PJM's expectations across the entire period when a unit is expected to be online or dispatchable for each start up, even across Segments or Operating Days.

values. In this case, PJM's practice is to calculate hourly values and then divide by 12 to convert the result into a five-minute value.

C. Overview of Exhibit No. Morelli-0001

81. I explain how each step of the proposed balancing Energy Make Whole credit equation works by using a simplified example (Exhibit No. Morelli-0001) based on a hypothetical resource's operation in two Real-time Settlement Intervals in a single Segment of an Operating Day—referred to in Exhibit No. Morelli-0001 as Segment 1, Interval 1 and Segment 1, Interval 2.

82. The example shows how the first two steps of the proposed balancing Energy Make Whole credit equation are applied in each Real-time Settlement Interval and how the third step is applied to the Segment.

83. As I noted, PJM's settlements practice is to calculate hourly values then divide by 12. To show how the proposed equation works, the hourly values are divided by 12 so that the results are represented in $/five-minute Real-time Settlement Interval.

84. The Incremental Energy Offer, which is the Committed and Final Offer for the hypothetical resource is as follows:

Offer Segment[63]	**Begin MW**	**End MW**	**Price**
1	0	50	$20.00
2	50	75	$25.00
3	75	100	$30.00

85. The Synchronized Reserve offer price is $0/MWh.

86. The resource has not limited its flexibility in Interval 1, but it has in Interval 2.

87. In both Interval 1 and Interval 2, the hypothetical resource is committed in the Day-ahead Energy Market, but PJM instructs the resource to operate at a higher MWh

[63] To be clear, "Offer Segment" refers to how Market Participants may offer different portions of their MW output at different prices. It does not refer to a resource's Segments of Real-time Settlement Intervals in an Operating Day.

level in real-time. The resource deviates from PJM's expectations, producing fewer MWh in the Real-time Energy Market than PJM expected. The resource's Economic Minimum is 50 MWh and its Economic Maximum is 100 MWh at the time of commitment.

D. Step 1: Tracking Balancing Energy Make Whole Credit

1. Interval 1

88. In Step 1 of the proposed balancing Energy Make Whole credit equation, the first calculation is to determine Tracking Balancing Net Revenue using TRLD MWh for each Real-time Settlement Interval in each Segment of a pool-scheduled resource's Operating Day.

89. The relevant *hourly* inputs for Segment 1, Interval 1 are given as follows[64]:

- The hypothetical resource has an Economic Minimum of 50 MWh and an Economic Maximum of 100 MWh in the Day-ahead Energy Market.
- The resource is committed in the Day-ahead Energy Market at the level of 75 MWh. The Day-ahead LMP is $28/MWh.
- The day-ahead energy make whole payment is $0.
- In the Day-ahead Synchronized Reserve Market, the resource is committed for 25 MWh. The Day-ahead Synchronized Reserve Market clearing price is $22.50/MWh.
- The resource reduces its Economic Maximum in the real-time market, such that its Economic Maximum is now 50 MW—the same as its Economic Minimum.
- In the Real-time Energy Market, the hypothetical resource is expected to provide 100 MWh, i.e. it has a TRLD MWh metric of 100 MWh.[65] The Real-time LMP is $60/MWh.

[64] Exh. No. Morelli-0001 at 1.

[65] Under the proposed rules, TRLD MW will be calculated using the originally submitted Economic Maximum output if the resource reduces its Economic Maximum by more than 5% subsequent to being committed (Tariff, Attachment K-Appendix, section 3.2.3(e-1)(i)).

- In the Real-time Synchronized Reserve Market, the resource is not assigned any Synchronized Reserve. The Real-time Synchronized Reserve Market clearing price is $45/MWh.

- Because the resource is not assigned Real-time Synchronized Reserve, Unadjusted TRLD MWh and TRLD MWh both equal 100 MWh. The resource actually operates in the Real-time Energy Market at 47 MWh. In other words, the resource deviates from PJM's expectations in the Real-time Energy Market, under-producing by 53 MWh.

90. Tracking Balancing Net Revenue is the net profit (or loss) a resource would have earned had it performed in the Real-time Energy Market in accordance with PJM's expectations throughout the resource's commitment period, as measured using TRLD MWh.[66] To determine Tracking Balancing Net Revenue for each Real-time Settlement Interval, the Real-time Cost the resource would have incurred had the resource operated as PJM expected (as calculated using TRLD MWh) is subtracted from the total Revenue the resource would have earned in that Real-time Settlement Interval had the resource operated as PJM expected (as calculated using TRLD MWh). Thus, in each interval, as set forth in the proposed Tariff[67]:

$$\textit{Tracking Balancing Net Revenue}_t = (\textit{DA Revenue}_t + \textit{Balancing Revenue}_t + \textit{Other Market Revenue}_t + \textit{Opportunity Cost Owed}_t) - \textit{Real-time Cost}_t$$

Where

t = *the Real-time Settlement Interval*

91. With respect to the hypothetical resource in Exhibit No. Morelli-0001, I calculate Tracking Balancing Net Revenue for t = Segment 1, Interval 1 and t = Segment 1, Interval 2, respectively.

92. In Segment 1, Interval 1 of the hypothetical resource in Exhibit No. Morelli-0001[68]:

$$\textit{Tracking Balancing Net Revenue}_t = (\textit{DA Revenue}_t + \textit{Balancing Revenue}_t + \textit{Other Market Revenue}_t + \textit{Opportunity Cost Owed}_t) - \textit{Real-time Cost}_t$$

[66] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2)(i).

[67] *Id.*

[68] Exh. No. Morelli-0001 at 1.

Tracking Balancing Net Revenue$_1$ = ($175 + $125 + -$46.88 + $47.92) – $354.17

= -$53.12[69]

93. In the subsections below, I provide the equations for and explain each of the components of Tracking Balancing Net Revenue$_t$—(a) DA Revenue$_t$, (b) Balancing Revenue$_t$, (c) Other Market Revenue$_t$, (d) Opportunity Cost Owed$_t$, and (e) Real-time Cost$_t$. I demonstrate, using the example set forth in Exhibit No. Morelli-0001, how each of these components are derived.

a. DA Revenue$_t$

94. DA Revenue$_t$ is the revenue earned by the resource in the Day-ahead Energy Market. As set forth in the proposed Tariff, DA Revenue for a Real-time Settlement Interval is derived in accordance with the following equation[70]:

DA Revenue$_t$ =Day-ahead Scheduled MWh × Day-ahead LMP

95. The assumed *hourly* values of the hypothetical resource in Exhibit No. Morelli-0001 are a Day-ahead MWh of 75 MWh and a Day-ahead LMP of $28/MWh. Thus[71]:

DA Revenue = 75 MWh x $28/MWh = $2,100

96. Thus, in Interval 1 of the hypothetical resource represented in Exhibit No. Morelli-0001:

DA Revenue$_1$ = 75 MWh x $28/MWh / 12 = $175

b. Balancing Revenue$_t$, Including Company Responsible Negative Revenues

97. Balancing Revenue$_t$ is the Balancing Energy Market Revenue in a Real-time Settlement Interval.[72] Because any MW scheduled in the Day-ahead Energy Market is already settled at day-ahead prices, only the difference between RT MWh

[69] Here and in other examples throughout this section of the affidavit, sums may differ by a penny depending on decimal precision in the spreadsheets used to calculate these values.

[70] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2)(i).

[71] Exh. No. Morelli-0001 at 1.

[72] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2)(i).

and Day-ahead MWh will be compensated at real-time prices. The equation for a single Real-time Settlement Interval, as set forth in the proposed Tariff, is as follows[73]:

Balancing Revenue$_t$ = (TRLD MWh ─ Day-ahead Scheduled MWh) × Real-time LMP ─ Company Responsible Negative Revenues

98. Company Responsible Negative Revenues is an input to the Balancing Revenue calculation that was not previously reflected in the status quo equation. Company Responsible Negative Revenues consist of "any negative balancing revenues in excess of the Day-ahead Energy Market revenue that results from the Market Participant's actions reducing the resource's flexibility as further specified in the PJM Manuals."[74]

99. PJM is proposing to subtract Company Responsible Negative Revenues from Balancing Revenue to ensure that the resource, not the market, is held responsible for costs associated with any reduction to the resource's dispatchable range subsequent to being committed. The Company Responsible Negative Revenues input into Balancing Revenue ensures that if the resource would have been dispatched higher or lower based on the resource's originally submitted dispatchable range when compared against the resource's desired MW based on the dispatchable range available in real-time, any losses associated with the reduction in dispatchable range are excluded from the real-time energy make whole credit calculated using TRLD MWh. As a result, a resource will not be made whole for any buy back in excess of day-ahead revenue due to the decrease in the resource's dispatchable range. The cost of any such buy back will be the responsibility of the Market Participant. Thus, subtracting the Company Responsible Negative Revenues from Balancing Revenue prevents a resource from being made whole for derated MW that were not desired by PJM. According to the proposed Tariff[75]:

Company Responsible Negative Revenues = MW unavailable due to limited flexibility × Min (Day-ahead LMP ─ Real-Time LMP, 0)

100. In Segment 1, Interval 1, although the hypothetical resource has limited its flexibility by reducing its Economic Maximum from 100 MWh to 50 MWh, TRLD

[73] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2)(i).

[74] *Id.*

[75] *Id.* section 3.2.3(e-2)(ii).

MWh is higher than the resource's day-ahead scheduled MWh.[76] The resource therefore does not need to buy back any of its day-ahead scheduled MWh and there are no negative balancing revenues associated with the reduction in flexibility. The amount of Company Responsible Negative Revenues is therefore $0.[77]

101. The relevant assumed *hourly* values of the hypothetical resource in Exhibit No. Morelli-0001 are: TRLD MWh of 100 MWh, day-ahead scheduled MWh of 75 MWh, Real-time LMP of $60/MWh, and Company Responsible Negative Revenues of $0.[78] The resource was committed for 75 MWh in the Day-ahead Energy Market when the Day-ahead LMP was $28. In real-time, greater demand increases the Real-time LMP to $60/MWh.[79] The resource's RT Desired MW is at 100 MWh, or 25 MWh higher than the resource's day-ahead committed MWh.[80] Thus:

Balancing Revenue = (TRLD MWh ─ Day-ahead Scheduled MWh) × Real-time LMP ─ Company Responsible Negative Revenues

Balancing Revenue = (100 MWh ─ 75 MWh) × $60/MWh ─ $0 = $1,500

Therefore, in Interval 1 of the hypothetical resource represented in Exhibit No. Morelli-0001:

Balancing Revenue$_1$ = ((100 MWh ─ 75 MWh) × $60/MWh ─ *$0) / 12 = $ 125*

102. Had the hypothetical resource performed as PJM expected in Segment 1, Interval 1, the resource would have received $125 in Balancing Revenue.

c. Other Market Revenue$_t$

103. Under the status quo rules, revenues earned from other markets and services are reflected as Net Ancillary Services profits on the Value side of the equation. In a simplified representation of the status quo rules, the Value side of the status-quo rules are represented as:

[76] Exh. No. Morelli-0001 at 1.

[77] *Id.*

[78] *Id.*

[79] *Id.*

[80] *Id.*

Value = Balancing Revenue + DA Revenue + DA Energy Make Whole Credit + Net Ancillary Services Profits and Other Revenues

104. Under the status quo equation, only revenues earned from the provision of services other than energy *in excess of both offer costs and opportunity costs* are included.[81] This means that revenues paid to resources through opportunity costs—which compensate resources for profits they could have made in the energy market in excess of their incremental energy offer for the MW the resource dedicated to providing the requested ancillary service instead—are excluded from the status quo calculation.

105. PJM is proposing to add Other Market Revenue as a component to the Value side of the balancing Energy Make Whole credit calculation. Some, but not all, of the inputs into Other Market Revenue are currently represented in the Net Ancillary Services Profits component of the status quo equation.

106. Other Market Revenue, as depicted in the proposed calculation, includes the same Net Ancillary Services Profits reflected in the existing equation, but additionally includes opportunity costs associated with the resource's provision of other products and services.[82] The Other Market Revenue equation is functionally equivalent to adding opportunity costs to the status quo Net Ancillary Services Profits input reflected on the Value side of the equation.

107. In the course of evaluating the existing balancing Operating Reserve credit equation, PJM and the Independent Market Monitor for PJM ("Market Monitor") recognized that the practice of excluding opportunity costs may understate a resource's revenues and potentially result in paying a resource make whole credits to cover costs already covered by revenue paid through opportunity costs in other markets. By recognizing opportunity costs paid through other markets as revenues that may offset the cost of energy produced, the revised equation avoids overpayment of make whole credits when they are not otherwise needed.

[81] This is reflected in Tariff, Attachment K-Appendix, section 3.2.3(e) as the absolute value of any negative Synchronized Reserve lost opportunity cost credit, the absolute value of any negative Non-Synchronized Reserve lost opportunity cost credit, the absolute value of any negative Secondary Reserve lost opportunity cost credit and any amounts credited for providing Reactive Services.

[82] Proposed Tariff, Attachment K-Appendix, sections 3.2.3(e-2)(i)-(ii).

108. As set forth in the proposed Tariff, in Step 1 of the proposed equation, Other Market Revenue reflects the *potential* revenue earned from other markets, with exception to Non-Synchronized Reserve Market credits.[83] Thus[84]:

Other Market Revenue$_t$ *= SR + SecR + NSR + Reactive + LOC + Reg*

Where

SR = any potential credits for providing Synchronized Reserve determined in accordance with the credit calculations in Tariff, Attachment K-Appendix, section 3.2.3A(b) less the resource's Synchronized Reserve offer price, in dollars, included in the resource's Synchronized Reserve potential lost opportunity cost credit in Tariff, Attachment K-Appendix, section 3.2.3A(f)(iv).

SecR = any potential credits for providing Secondary Reserve determined in accordance with the credit calculations in Tariff, Attachment K-Appendix, section 3.2.3A.01(b)

NSR = any amounts credited for providing Non-Synchronized Reserve as specified in Tariff, Attachment K-Appendix, section 3.2.3A.001(b)

Reactive = any potential credits for providing Reactive Services determined in accordance with the credit calculations in Tariff, Attachment K-Appendix, section 3.2.3B

LOC = any potential lost opportunity cost credits determined in Tariff, Attachment K-Appendix, sections 3.2.3(f) – 3.2.3(f-6).

[83] Exh. No. Morelli-0001 at 1. Potential reserve market revenues under Step 1 may differ from the actual reserve market revenues under Step 2 because: 1) the opportunity costs differ between the two steps, and/or 2) the reserve market clearing price credits differ due to the credits being capped under Step 2 due to the application of existing rules that limit payment when resources over-generate and cannot deliver the assigned reserves, while Step 1 does not cap such revenues because it assumes the resource operated as expected and could deliver the assigned reserves. However, Non-Synchronized Reserve revenues are always the same between Step 1 and Step 2. This is because Non-Synchronized Reserves are provided by offline resources. The tariff states that opportunity costs are $0 for Non-Synchronized Reserve resources, so $0 opportunity cost is assumed for both Step 1 and Step 2. Further, because this service is provided by offline resources, there is no capping applied to Non-Synchronized Reserve market credits in Tariff, Attachment K-Appendix, section 3.2.3A.001(b) and Operating Agreement, Schedule 1, section 3.2.3A.001(b) because the nature of an offline resource means there is no overgeneration to trigger the need for such capping. The Non-Synchronized Reserve clearing price credits are therefore the same in both Step 1 and Step 2.

[84] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2)(i).

Reg = any potential Regulation opportunity cost amounts determined in accordance with the calculations for use in settlements in Tariff, Attachment K-Appendix, section 3.2.2.

109. To be clear, opportunity costs are not actually costs incurred in the production of energy. Rather, opportunity costs represent profits, or positive net revenues, that a resource gives up in the energy market when it provides an alternative service (e.g., Synchronized Reserve) in response to PJM's dispatch instructions. These forgone profits are actually paid to the resource through other markets (e.g., the Ancillary Services Market).

110. In accordance with the definition of Synchronized Reserve for purposes of the Other Market Revenue calculation, the resource's Other Market Revenue is equal to "any potential credits for providing Synchronized Reserve determined in accordance with the credit calculations in [the Tariff] less the resource's Synchronized Reserve offer price, in dollars, included in the resource's Synchronized Reserve potential lost opportunity cost credit in [the Tariff]."[85] In other words, Other Market Revenue from the provision of Synchronized Reserve is equal to the resource's Synchronized Reserve Market clearing price credits plus Synchronized Reserve Lost Opportunity Cost credits less the Synchronized Reserve offer price a resource would receive from producing TRLD MWh.[86]

111. In accordance with the Tariff, Other Market Revenue is equal to the Day-ahead Synchronized Reserve Market clearing price credit, plus the balancing Synchronized Reserve Market clearing price credit, plus the Synchronized Reserve Lost Opportunity Cost credit, minus the resource's Synchronized Reserve offer price as described in the Tariff.[87]

112. In Segment 1, Interval 1 of the hypothetical resource in Exhibit No. Morelli-0001, unadjusted TRLD MWh is equal to 100 MWh, which is the resource's Economic Maximum.[88] The resource has a Day-ahead Synchronized Reserve assignment of 25 MWh at a day-ahead clearing price of $22.50/MWh.[89] Subsequently, the Real-time Synchronized Reserve Assignment becomes 0 MWh with a real-time clearing

[85] Proposed Tariff, Attachment K-Appendix, sections 3.2.3(e-2)(i)-(ii).

[86] *See also* Tariff, Attachment K-Appendix, section 3.2.3A(f)(iv).

[87] *Id.* section 3.2.3A(b).

[88] Exh. No. Morelli-0001 at 1.

[89] *Id.*

price of $45/MWh.[90] The hypothetical resource receives no additional Other Market assignments. The Synchronized Reserve Market is the only ancillary service market in which the resource was assigned MWh. Thus[91]:

1) Day-ahead Synchronized Reserve Market clearing price credit = 25 MWh x $22.50/MWh = $562.50

Or, divided into five-minute Intervals, $46.88

2) balancing Synchronized Reserve Market clearing price credit = (0 MWh – 25 MWh) x $45/MWh = -$1,125

Or, divided into five-minute Intervals, -$93.75

3) Lost opportunity cost credit of $0, as explained further below.

4) Synchronized Reserve offer price of $0/MWh

The sum of the above credits, minus the offer price, divided into five-minute Intervals is -$46.88.

Other Market Revenue in Segment 1, Interval 1 = -$46.88.

113. Lost Opportunity Cost Credits compensate a resource for a) any Synchronized Reserve offer price plus any day-ahead and real-time opportunity costs not covered by day-ahead and balancing reserve market clearing price credits, as well as for b) any negative balancing revenue (essentially a cost) associated with buying out of the day-ahead reserve assignment at PJM's direction. In this case, the resource had a $0/MWh Synchronized Reserve offer price and forewent $1.04 of energy profit by providing the 25 MWh Day-ahead Synchronized Reserve assignment in this five-minute interval.[92] The resource was not assigned Synchronized Reserves in the real-time market and therefore did not forgo any energy profit in real-time. In total, the resource had an offer price plus opportunity cost of $1.04.

114. The resource's Synchronized Reserve assignment was reduced from a day-ahead commitment of 25 MWh to 0 MWh in real-time and therefore had to buy back

[90] Exh. Morelli-0001 at 1.

[91] *Id.*

[92] This is calculated as the revenue from producing 25 MWh of energy at $28/MWh ($700) minus the cost of MW 75 through 100 on the incremental energy offer curve ($687.50) divided by 12.

25 MWh of Synchronized Reserve at the Real-time Synchronized Reserve Market clearing price of $45/MWh. This yields a balancing Synchronized Reserve Market Clearing Price Credit of -$1,125, or -$93.75 per five-minute Interval. This is essentially a cost of $93.75.

115. Thus, the resource would typically receive a Lost Opportunity Cost Credit of $47.92. This is calculated by adding the opportunity cost of $1.04 and the cost of buying out of the day-ahead reserve assignment of $93.75, and then subtracting the Day-ahead Synchronized Reserve Market Clearing Price credit of $46.88. However, in order to be eligible to recover the cost of buying out of the day-ahead reserve assignment via Lost Opportunity Cost Credits, a resource cannot act in a manner that results in the resource's real-time reserve assignment being less than its day-ahead assignment. Otherwise, the cost is the responsibility of the Market Seller and it is captured through Opportunity Cost Owed, which is an existing offset in the Lost Opportunity Cost Credit calculation that reduces the amount otherwise paid to the resource.

116. In this example, the resource reduced its Economic Maximum output to its Economic Minimum Output of 50 MW in real-time. This left no room for the resource to provide Synchronized Reserves in real-time. Thus, the resource's own actions caused the need to buy back the day-ahead reserve assignment and the $93.75 cost of buying out of the day-ahead reserve assignment is not eligible to be made whole via Lost Opportunity Cost Credits. Opportunity Cost Owed is the max of the $93.75 cost of buying out of the Day-ahead Energy Market and the Lost Opportunity Cost Credit calculated before accounting for Opportunity Cost Owed, or $47.92. Thus, Opportunity Cost Owed is $47.92. This reduces the Lost Opportunity Cost Credit to $0.

117. Thus, because the resource had to buy out of its day-ahead reserve position at a real-time price greater than what it received in the day-ahead reserve market, and because the resource was ineligible to be made whole for that buy out, Other Market Revenue is negative in this hypothetical example. For Segment 1, Other Market Revenue = -$46.88.

d. $\underline{\text{Opportunity Cost Owed}_t}$

118. PJM is proposing to add Opportunity Cost Owed to the Value side of Step 1 of the proposed balancing Energy Make Whole credit equation.

119. If the resource's own actions cause the resource to provide fewer MWh in the real-time reserve market than cleared in the day-ahead reserve market, Opportunity Cost Owed is added to the Value side of the proposed balancing Make Whole Credit equation. This prevents the resource from being made whole via balancing Energy Make Whole credits for costs which the resource was not eligible to be made whole for via the reserve market. because of the resource's own actions which are contrary to the Step 1 principle of operating as expected by PJM.

e. Real-time $Cost_t$

120. For purposes of calculating Tracking Balancing Net Revenue, a resource's Real-time Cost in each five-minute Real-time Settlement Interval within Segment 1 is as follows:

Real-time Cost$_t$ *= Incremental Offer Costs+ No Load Cost + Start-up Cost*

121. The hypothetical resource's Start-up Costs are $0/hour, and No Load Costs are $2,000/hour.[93] In the Real-time Energy Market, the resource's TRLD MWh is 100 MWh.[94] The Incremental Offer Costs are as follows[95]:

Offer Segment	Begin MW	End MW	Price
1	0	50	$20.00
2	50	75	$25.00
3	75	100	$30.00

[93] Exh. No. Morelli-0001 at 1.

[94] *Id.*

[95] *Id.*

Incremental Offer Costs (TRLD MWh)					
Offer Segment	**Begin MW**	**End MW**	**Begin Price**	**End Price**	**Offer Cost**
1	0	50	$20.00	$20.00	$1,000.00
2	50	75	$20.00	$25.00	$562.50
3	75	100	$25.00	$30.00	$687.50
					$2,250.00

122. The *hourly* Real-time Cost is:

Real-time Cost/hr= Incremental Offer Costs+ No Load Cost + Start-up Cost

Real-time Cost/hr = $2,250/hr + $2,000/hr + $0 = $4,250/hr

123. Thus, the Real-time Cost for Segment 1, Real-time Settlement Interval 1 of the hypothetical resource is:

Real-time Cost$_t$= (2,250/hr+ $2,000/hr + $0) / 12 = $354.17

2. Interval 2

124. Next, using the example set forth in Exhibit No. Morelli-0001, I walk through the calculation of Tracking Balancing Net Revenue using TRLD MWh for Real-time Settlement Interval 2. It can be assumed that the values reflected in the Tracking Balancing Net Revenue$_t$ calculation for Interval 2 were derived in the same way as described above, for Interval 1.

125. The relevant *hourly* inputs for Segment 1, Interval 2 are given as follows[96]:

- The hypothetical resource is committed in the Day-ahead Energy Market at the level of 50 MWh. The Day-ahead LMP is $32/MWh.
- The day-ahead energy make whole payment is $0.

[96] Exh. No. Morelli-0001 at 2.

- The resource does not receive a Day-ahead Synchronized Reserve Market assignment.

- In the Real-time Energy Market, the hypothetical resource is expected to provide 75 MWh of energy, i.e. it has a TRLD MWh metric of 75 MWh. The Real-time LMP is $57/MWh.

- The resource receives a Real-time Synchronized Reserve Market assignment of 25 MWh. The Real-time Synchronized Reserve Market clearing price is $26/MWh.

- Unadjusted TRLD MWh is 100 MWh, which is the resource's Economic Maximum. In order to provide the 25 MWh of Synchronized Reserve, TRLD MWh is 75 MWh.

- The resource actually operates in the Real-time Energy Market at 50 MWh. In other words, the resource deviates from PJM's expectations in the Real-time Energy Market, under-producing by 25 MWh.

126. In Segment 1, Interval 2 of the hypothetical resource in Exhibit No. Morelli-0001[97]:

Tracking Balancing Net Revenue$_t$ = (DA Revenue$_t$ + Balancing Revenue$_t$ + Other Market Revenue$_t$ + Opportunity Cost Owed$_t$) - Real-time Cost$_t$

Tracking Balancing Net Revenue$_2$ = ($133.33 + $118.75 + $61.46 + 0) - $296.88 = $16.67

127. While I will not repeat the reasoning behind each of the components to the Tracking Balancing Net Revenue calculation, I will point out a couple of noteworthy observations about Interval 2, in which the resource receives no Other Market assignments in the Day-ahead Energy Market, and is then assigned 25 MWh of Synchronized Reserve in the Real-time Energy Market.[98] The resource does not have assignments in any other ancillary service markets.[99]

128. Because the resource received a 25 MWh Real-time Synchronized Reserve assignment, and the unadjusted TRLD MWh was 100 MWh, or Economic

[97] Exh. Morelli-0001 at 2.

[98] *Id.*

[99] *Id.*

Maximum, TRLD MWh is adjusted to 75 MWh to allow headroom for the additional Real-time Synchronized Reserve assignment.[100]

129. Synchronized Reserve credits represented in Other Market Revenue in Step 1 of the proposed equation include *potential* profits a resource could have made in the energy market in excess of the resource's incremental energy offer had the resource *not* been called on to provide Synchronized Reserve. These Synchronized Reserve opportunity costs are profits that a resource would recover through Synchronized Reserve lost opportunity cost credits or through Synchronized Reserve clearing price credits.

130. In accordance with the Tariff, Other Market Revenue is equal to sum of the Day-ahead Synchronized Reserve Market clearing price credit, the balancing Synchronized Reserve Market clearing price credit, and the Synchronized Reserve Lost Opportunity Cost credit, minus the Synchronized Reserve offer price as described in the Tariff.[101]

1) Day-ahead Synchronized Reserve Market clearing price credit = 0 MWh x $27.50/MWh = $0

2) balancing Synchronized Reserve Market clearing price credit = (25 MWh – 0 MWh) x $26/MWh = $650

Or, divided into five-minute Intervals, $54.17

3) Lost Opportunity Cost Credit = $7.29

4) Synchronized Reserve offer price of $0/MWh

The sum of the above credits, minus the offer price, divided into five-minute Intervals is $61.46

Other Market Revenue in Segment 1, Interval 2 = $61.46

131. In this hypothetical example, Lost Opportunity Cost Credit is compensating the resource for real-time opportunity costs not covered by the balancing reserve market clearing price credits. In this case, the resource forewent $61.46 of profit

[100] Exh. Morelli-0001 at 2.

[101] Tariff, Attachment K-Appendix, section 3.2.3A(b).

in the real-time energy market by providing only 75 MWh of energy (the Tracking Desired MWh) instead of 100 MWh of energy (the unadjusted Tracking Desired MWh) it would have been most profitable to produce in order to provide the 25 MWh real-time Synchronized Reserve assignment in this 5-minute interval.[102] Because the resource only earned $54.17 in balancing Synchronized Reserve Market clearing price credits, Lost Opportunity Cost credits provide the difference of $7.29 to ensure the resource earns enough to cover its opportunity cost.[103]

132. In this interval, Other Market Revenue is positive. Had the resource performed in the Real-time Energy Market as expected, while also providing the assigned real-time Synchronized Reserve as PJM expected, the resource would have received $61.46 in Other Market Revenue for its performance in Interval 2. [104] In other words, the resource would have received a balancing Synchronized Reserve Market clearing price credit of $54.17 (or $650 / 12) from having provided 25 MWh at the Real-time Synchronized Reserve Market clearing price of $26/MWh, plus a lost opportunity cost credit of $7.29 (or $87.48 / 12).[105]

133. With respect to Opportunity Cost Owed in Segment 1, Interval 2 of the hypothetical resource, had the resource performed as PJM expected, the resource would have $0 in Opportunity Cost Owed in Segment 1, Interval 2.[106] Because the resource's assignment in the Real-time Synchronized Reserve Market increased as compared to day-ahead, the resource had no need to buy out of its Day-ahead Synchronized Reserve assignment.

[102] This is calculated as the revenue from producing 25 MWh of energy at $57 ($1425) minus the cost of MW 75 through 100 on the incremental energy offer curve ($687.50) divided by 12.

[103] Exh. No. Morelli-0001 at 2.

[104] *Id.*

[105] *Id.*

[106] *Id.*

3. Segment 1: Tracking Balancing Energy Make Whole Credit

134. The final calculation of Step 1 is to total Tracking Balancing Net Revenue across all Real-time Settlement Intervals in the Segment to determine the Tracking Balancing Energy Make Whole Credit.[107] As set forth in the proposed Tariff:

Tracking Balancing Energy Make Whole Credit = A – B

Where

$A = -1 \times \sum_t$ *Tracking Balancing Net Revenue*$_t$

Where t = the eligible Real-time Settlement Intervals in the applicable Segment

B = Day-ahead Energy Make Whole Credit as determined pursuant to section 3.2.3(b) if the Segment is the first Segment. For all other Segments, B = 0.

Tracking Balancing Energy Make Whole Credit shall not be less than zero.

135. In this case[108]:

$A = -1 \times \sum_t$ *Tracking Balancing Net Revenue*$_t$

Where t = the eligible Real-time Settlement Intervals in the applicable Segment

Tracking Balancing Net Revenue$_1$ = -$53.12

Tracking Balancing Net Revenue$_2$ = $16.67

A = -1 x (-$53.12 + $16.67)

= $36.46

B = Day-ahead Energy Make Whole Credit as determined pursuant to section 3.2.3(b) if the Segment is the first Segment.

Day-ahead Energy Make Whole Credit = $0[109]

[107] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2)(i).

[108] Exh. No. Morelli-0001 at 3.

[109] For the sake of simplicity, the day-ahead energy make whole credit is assumed to be $0.

Tracking Balancing Energy Make Whole Credit = A – B

= $36.46 - $0

=$36.46

E. Step 2: Actual Balancing Energy Make Whole Credit

136. Actual Balancing Net Revenue is the net profit (or loss) a resource earned based on the resource's actual performance in the Real-time Energy Market and other markets throughout the resource's commitment period, as measured using Actual MWh.[110] As set forth in the proposed Tariff, "the Actual MWh equals the Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Operating Agreement, Schedule 1, section 3.1A."[111]

137. To determine Actual Balancing Net Revenue for each Real-time Settlement Interval, the Real-time Cost the resource incurred based on its actual operation, as calculated using Actual MWh, is subtracted from the total Revenue the resource earned in that Real-time Settlement Interval based on its actual operation, as calculated using Actual MWh.[112]

138. In Step 2 of the proposed balancing Energy Make Whole credit equation, PJM first determines Actual Balancing Net Revenue using Actual MWh for each pool-scheduled Real-time Settlement Interval in each Segment of an Operating Day. The Step 2 equation for calculating Actual Balancing Net Revenue in each Interval is:

$$Actual\ Balancing\ Net\ Revenue_t = (DA\ Revenue_t + Balancing\ Revenue_t + Other\ Market\ Revenue_t) - Real\text{-}time\ Cost_t$$

139. The Step 2 equation is structurally identical to the Step 1 equation, with exception to the following significant differences:

- The Step 2 equation uses Actual MWh rather than TRLD MWh. In Step 2, PJM calculates the amount of make whole credit a resource requires based on how it *actually* operated, inclusive of any deviations from PJM commitment and dispatch instructions. PJM calculates the difference

[110] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2)(i).

[111] *Id.* section 3.2.3(e-2)(ii).

[112] *Id.* section 3.2.3(e-2)(i).

between the resource's actual Cost and the resource's actual Value (revenue) to determine the Cost to which the resource would be made whole were PJM to credit the resource based on its actual operation.

- The inputs to Other Market Revenue represent *actual* amounts credited to the resource for Synchronized Reserve, Secondary Reserve, Non-Synchronized Reserve, Reactive Services, and lost opportunity cost credits.

- Because Opportunity Cost Owed is not an amount that the resource has actually received as revenue, Opportunity Cost Owed is not included in Actual Balancing Net Revenue. This is in keeping with the principle that Step 2 represents actual revenues based on actual operation.

1. Interval 1

140. The Step 2 calculation results in the following result for Segment 1, Interval 1 of the hypothetical resource in Exhibit No. Morelli-0001[113]:

Actual Balancing Net Revenue$_t$ = (DA Revenue$_t$ + Balancing Revenue$_t$ + Other Market Revenue$_t$) - Real-time Cost$_t$

Actual Balancing Net Revenue$_1$ = ($175 + -$73.33 + -$46.88) – $245 = -$190.21

Balancing Revenue$_t$ = (Actual MWh ─ Day-ahead Scheduled MWh) × Real-time LMP ─ Company Responsible Negative Revenues

Balancing Revenue = (47 MWh ─ 75 MWh) × $60/MWh ─ $800 = $880

Therefore, in Interval 1 of the hypothetical resource represented in Exhibit No. Morelli-0001[114]:

Balancing Revenue$_1$ = (47 MWh ─ 75 MWh) × $60/MWh 12 *─ $800/12 = $ 73.33*

141. Recall that for Segment 1, Interval 1, Company Responsible Negative Revenue was $0 in the Step 1 Balancing Revenue calculation when calculated using TRLD MWh. This was because although the hypothetical resource has limited its flexibility by reducing its Economic Maximum from 100 MWh to 50 MWh in this

[113] The Real-time Cost component of $245 is the result of applying the incremental energy offer curve, described above, to the resource's Actual MWh of 47 MWh.

[114] Exh. No. Morelli-0001 at 1.

interval, TRLD MWh was 100 MWh, which is higher than the resource's day-ahead scheduled MWh. This meant the resource did not need to buy back any of its day-ahead scheduled MWh and there were no negative balancing revenues associated with the reduction in flexibility. Thus, Company Responsible Negative Revenues in the Step 1 calculation is $0/MWh.

142. However, here in the Step 2 Balancing Revenue calculation, which uses Actual MWh, the Company Responsible Negative Revenues are non-zero.[115] The resource's Actual MWh was only 47 MWh, which is lower than the 75 MWh scheduled in the Day-ahead Energy Market. The balancing revenue reflects the cost of buying out of 28 MWh of its day-ahead commitment.[116] However, 25 MWh of that buy out is a direct result of the resource reducing its Economic Maximum from 100 MWh to 50 MWh subsequent to being committed.[117] The subtraction of the Company Responsible Negative Revenues term ensures any losses, meaning, in this case, balancing costs in excess of day-ahead revenues, associated with the reduction in dispatchable range are excluded from the real-time energy make whole credit. Any such loss will be the responsibility of the Market Seller. As a result, a resource will not be made whole for any buy back in excess of day-ahead revenue due to the decrease in the resource's dispatchable range. According to the proposed Tariff[118]:

Company Responsible Negative Revenues = MW unavailable due to limited flexibility × Min (Day-ahead LMP ─ Real-Time LMP, 0)

*Company Responsible Negative Revenues = 25 MWh * Min($28/MWh – 60/MWh, 0) / 12 = -$800*

$$\textit{Company Responsible Negative Revenues}_t = -\$800 / 12 = -\$66.67$$

143. As I noted above, in Step 2, Other Market Revenue represent *actual* amounts credited to the resource for Synchronized Reserve, Secondary Reserve, Non-Synchronized Reserve, Reactive Services, and lost opportunity cost credits. Because the resource only participated in the Synchronized Reserve market, Other Market Revenue is equal to sum of the Day-ahead Synchronized Reserve Market

[115] Exh. No. Morelli-0001 at 1.

[116] *Id.*

[117] The 25MWh of buy out that is the result of the reduction in dispatchable range is calculated as the DA Scheduled MWh of 75 minus the updated Economic Minimum of 50 MWh.

[118] Exh. No. Morelli-0001 at 1.

clearing price credit, the balancing Synchronized Reserve Market clearing price credit, and the Synchronized Reserve Lost Opportunity Cost credit, minus the Synchronized Reserve offer price as described in the Tariff.[119] Further, in Segment 1, Interval 1, the actual credits are the same as the potential credits given the resource did not have a real-time reserve assignment and it is the existence of real-time reserve assignments that can drive divergence in the Other Market Revenues between Steps 1 and 2.

Thus, the Other Market Revenue in Segment 1, Interval 1 = -$46.88.

2. Interval 2

144. The Step 2 calculation yields the following result for Segment 1, Interval 2 of the hypothetical resource in Exhibit No. Morelli-0001[120]:

Actual Balancing Net Revenue$_t$ = (DA Revenue$_t$ + Balancing Revenue$_t$ + Other Market Revenue$_t$) - Real-time Cost$_t$

Actual Balancing Net Revenue$_1$ = ($133.33 + $0 + $54.17) – $250 = -$62.50

145. To the extent these above Step 2 calculations are structurally identical to the Step 1 calculations, except that TRLD MWh is replaced with Actual MWh, it can be understood that similar logic and reasoning applies. Therefore, I will not break down the equation further when the only structural difference between Step 1 and Step 2 is replacing TRLD MWh with Actual MWh. However, I will elaborate briefly on differences in Step 1 and Step 2 with respect to Other Market Revenue and Opportunity Cost Owed.

146. In Step 2, Other Market Revenue captures actual, rather than potential, Other Market Revenue, which includes *actual* reserve market clearing price credits, which are reflective of any capping when the reserve market assignment is infeasible due to the resource over-generating, and *actual* lost opportunity cost credits:

Other Market Revenue = SR + SecR + NSR + Reactive + LOC + Reg

Where:

[119] Tariff, Attachment K-Appendix, section 3.2.3A(b).

[120] Exh. No. Morelli-0001 at 2.

SR = any amounts credited for providing Synchronized Reserve equal to the credits as determined in Tariff, Attachment K-Appendix, section 3.2.3A(b) less the resource's Synchronized Reserve offer price, in dollars, included in the resource's Synchronized Reserve lost opportunity cost credit calculation in Tariff, Attachment K-Appendix, section 3.2.3A(f)(iv)

SecR = any amounts credited for providing Secondary Reserve as determined in Tariff, Attachment K-Appendix, section 3.2.3A.01 (b)

NSR = any amounts credited for providing Non-Synchronized Reserve as determined in Tariff, Attachment K-Appendix, section 3.2.3A.001(b)

Reactive = any amounts credited for providing Reactive Services as determined in Tariff, Attachment K-Appendix, section 3.2.3B

LOC = any lost opportunity costs credits as determined in Tariff, Attachment K-Appendix, sections 3.2.3(f) – 3.2.3(f-6); and

Reg =any Regulation opportunity cost amounts as calculated for purposes of settlements in Tariff, Attachment K-Appendix, section 3.2.2

147. As I noted above, in Step 2, Other Market Revenue represent *actual* amounts credited to the resource for Synchronized Reserve, Secondary Reserve, Non-Synchronized Reserve, Reactive Services, and lost opportunity cost credits. Because the resource only participated in the Synchronized Reserve market, Other Market Revenue is equal to the sum of the Day-ahead Synchronized Reserve Market clearing price credit, the balancing Synchronized Reserve Market clearing price credit, and the Synchronized Reserve Lost Opportunity Cost credit, minus the Synchronized Reserve offer price as described in the Tariff.[121]

1) Day-ahead Synchronized Reserve Market clearing price credit = 0 MWh x $27.50/MWh = $0

2) balancing Synchronized Reserve Market clearing price credit = (25 MWh – 0 MWh) x $26/MWh = $650

Or, divided into five-minute Intervals, $54.17

3) Lost Opportunity Cost Credit = $0

4) Synchronized Reserve offer price of $0/MWh

[121] Tariff, Attachment K-Appendix, section 3.2.3A(b).

The sum of the above credits, minus the offer price, divided into five-minute Intervals is $54.17

Other Market Revenue in Step 2 for Segment 1, Interval 2 = $54.17

148. In Interval 2, Actual Other Market Revenue, reflected in Step 2, differs from potential Other Market Revenue reflected in Step 1.[122] Note that in Step 1, the Lost Opportunity Cost Credit was $7.29 because if the resource had been operating as expected by PJM (producing TRLD MWh) it would have had $61.46 in real-time opportunity costs due to being backed down from where it would otherwise be desired (Unadjusted TRLD MWh, which is the resource's Economic Maximum in this case) in order to provide Synchronized Reserve and those opportunity costs were not fully covered by the balancing reserve market clearing price credits the resource earned.[123] However, in Step 2, the Lost Opportunity Cost Credit was $0.[124] This is because the resource's Actual MWh was 50 MWh.[125] The resource had plenty of available ramping headroom between its Actual MWh and its Economic Maximum with which it could provide Synchronized Reserves. It did not need to be backed down from its economic dispatch point in order to provide the assigned reserves and therefore did not incur an opportunity cost.

Thus, the Other Market Revenue in Step 2 for Segment 1, Interval 2 = $54.17, which is less than the Other Market Revenue for that interval in Step 1 by $7.29 (the amount of the Step 1 Lost Opportunity Cost Credit).[126]

149. Opportunity Cost Owed is not an amount that represents actual revenues received by the resource and, therefore, is not included in Step 2.[127]

3. Segment 1: Actual Balancing Energy Make Whole Credit

150. In this case the Actual Balancing Energy Make Whole Credit for Segment 1 equals[128]:

---

[122] Exh. No. Morelli-0001 at 2.

[123] *Id.*

[124] *Id.*

[125] *Id.*

[126] *Id.* at 3.

[127] *Id.*

[128] *Id.*

Actual Balancing Energy Make Whole Credit = A – B

Where

$A = -1 \times \sum_t$ *Actual Balancing Net Revenue*$_t$

Where t = the eligible Real-time Settlement Intervals in the applicable Segment

B = Day-ahead Energy Make Whole Credit as determined pursuant to section 3.2.3(b) if the Segment is the first Segment; else, 0

Actual Balancing Energy Make Whole Credit shall not be less than zero.

$A = -1 \times \sum_t$ *Actual Balancing Net Revenue*$_t$

Where t = the eligible Real-time Settlement Intervals in the applicable Segment

Actual Balancing Net Revenue$_1$ = -$190.21

Actual Balancing Net Revenue$_2$ = -$62.50

A = -1 x (-190.21 + -$62.50)

= $252.71

B = Day-ahead Energy Make Whole Credit as determined pursuant to section 3.2.3(b) if the Segment is the first Segment.

Day-ahead Energy Make Whole Credit = $0[129]

Actual Balancing Energy Make Whole Credit = A – B

= $252.71 - $0

=$252.71

F. Step 3

151. For each *Segment* in the Operating Day, the total real-time energy make whole credit paid to a resource will be the lesser of the Tracking Balancing Energy Make

[129] For the sake of simplicity, the day-ahead energy make whole credit is assumed to be $0.

Whole Credit, as calculated in Step 1, and the Actual Balancing Energy Make Whole Credit, as calculated in Step 2.[130]

152. In Exhibit No. Morelli-0001, Tracking Balancing Energy Make Whole Credit is equal to $36.46. Actual Balancing Energy Make Whole Credit is equal to $252.71.[131] Thus, the real-time energy make whole credit is $36.46.[132]

153. While, based on the resource's actual performance in the Real-time Energy Market, the resource incurred $252.71 in costs that were not covered by its revenue, the resource is only made whole to $36.46, which is the make whole credit that would have been necessary if the resource had operated as desired by PJM. Thus, the resource was *not* made whole for the $216.25 of its costs in excess of that value.

IV. ELIGIBILITY RULES

154. PJM is proposing to revise its status quo real-time make whole payment eligibility rules. In most cases, the proposed revisions will increase the number of Real-time Settlement Intervals in which PJM will consider a resource eligible to receive make whole payments. Notably, PJM is *not* proposing to extend these eligibility rules to deviation charges, which PJM will continue to calculate in every Real-time Settlement Interval in which a resource is not otherwise exempt from deviation charges. In the Real-time Settlement Intervals in which a resource is eligible, PJM applies the balancing Energy Make Whole credit equation. When applied in combination with other proposed rules, lengthening a resource's eligibility period enhances PJM's ability to measure how well a resource is operating compared to PJM's expectations of that resource during the full period in which PJM expected the resource to be operating. Eligibility in more Real-time Settlement Intervals will allow PJM to show the economic impact of a resource following and/or deviating from PJM's expectations throughout the resource's entire commitment period, even when the resource is offline.

155. My affidavit on this topic is organized as follows:

- In section IV.A, below, I provide a brief overview of the eligibility rules, which dictate the Real-time Settlement Intervals in which a resource will be

[130] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2).

[131] Exh. No. Morelli-0001 at 3.

[132] *Id.*

assessed real-time energy make whole credits. Eligibility in an Interval does not guarantee that the resource will receive make whole credits during that Interval. I also distinguish three different periods of time, each used to calculate make whole payments: (1) a resource's commitment time period; (2) the period in which PJM calculates a resource's TRLD; and (3) a resource's eligibility time period.

- In section IV.B, I address the proposed eligibility start time rules, and pre-commitment period eligibility rules specific to no soak resources, as set forth in proposed Tariff, Attachment K-Appendix, section 3.2.3(e)(i).

- In section IV.C, I address the proposed eligibility end time rules and eligibility in the post-commitment period, as set forth in proposed Tariff, Attachment K-Appendix, section 3.2.3(e)(i).

- In section IV.D, I address additional rules specific to the ramp-up periods of soak and no soak resources, as set forth in proposed Tariff, Attachment K-Appendix, sections 3.2.3(e-2)(i) and 3.2.3(e-2)(ii).

A. Overview of Eligibility Rules

156. The proposed revisions to eligibility, set forth primarily in proposed Tariff, Attachment K-Appendix, section 3.2.3(e), expand the eligibility window which creates benchmarks for: (1) what the costs and revenues would have been if a resource had operated as requested; and (2) the maximum level of real-time energy make whole credits that a resource would have been paid by operating as PJM expected. A resource's eligibility period can impact the real-time energy make whole credits paid to a resource in an Operating Day.

157. A resource's eligibility period may differ from its TRLD calculation period, even though both are measured in Real-time Settlement Intervals. Unlike a resource's TRLD calculation period, eligibility is derived from the resource's commitment period. The start and end time of TRLD and unadjusted TRLD reflect PJM's expectations for the resource by tracking when the resource is expected to be online or when a resource is expected to be dispatchable, while honoring soak time differences, regardless of whether the resource has a pool-scheduled or self-scheduled commitment. The start and end time of a resource's pool-scheduled commitment period is based on when a generation resource has been scheduled by PJM to run, and a resource's eligibility period is typically the same as its pool-scheduled commitment period, with exception to the limited circumstances,

described below, in which eligibility may start slightly before the start of the pool-scheduled commitment period or extend slightly beyond the end of the pool-scheduled commitment period while the resource is ramping offline after the resource has been released.

158. Currently, under the status quo rules, with exception to some latitude given to no soak resources for ramp up, a resource's eligibility period is limited to the time in which the resource is online and dispatchable pursuant to PJM's commitment instructions. That is, they must be online and dispatchable during a pool-scheduled commitment.[133] The eligibility period, under the status quo rules, ends as soon as a resource goes offline, but in no case more than three hours after the resource was released by PJM, or is otherwise turned over to operate as a self-scheduled resource.[134]

159. The revised rules, in most cases, lengthen the eligibility period such that eligibility starts and ends with a resource's pool-scheduled commitment period. By making resources eligible in more Real-time Settlement Intervals, the revised eligibility rules provide a fuller picture of the financial consequences of following or deviating from PJM's expectations. In Part V of my affidavit, below, I provide illustrative examples of the eligibility rules, TRLD, and balancing Energy Make Whole credit equation in application.

B. Eligibility Start Time

160. As set forth in proposed Tariff, Attachment K-Appendix, section 3.2.3(e)(i), "[a] pool-scheduled generation resource's eligibility for balancing Energy Make Whole credits begins at the first Real-time Settlement Interval of a pool-scheduled commitment." The first interval of a pool-scheduled commitment is the earliest interval in which the resource has any form of pool-scheduled commitment. For example, if a resource is committed in the Day-ahead Energy Market beginning at 9 AM, and subsequently instructed by PJM to revise its commitment start in the Real-time Energy Market to 10 AM, the first interval of a pool-scheduled commitment would begin at 9 AM.

161. "Additionally, generation resource types with no soak process in the Start-up Cost are eligible for balancing Energy Make Whole credits for a pre-commitment period

[133] Tariff, Attachment K-Appendix, section 3.2.3(e)(i); PJM Manual 28, section 5.2.1.

[134] *Id.*

prior to the first Real-time Settlement Interval of the pool-scheduled commitment to account for ramping costs."[135] In other words, eligibility start times can differ based on whether the resource is a soak or no soak unit.

162. With exception to "generation resource types with no soak process," shifting to "the first Real-time Settlement Interval of the pool-scheduled commitment" will lead to resources having earlier eligibility start times. By starting a resource's eligibility at the first Real-time Settlement Interval of a pool-scheduled commitment, regardless of whether the unit is online or dispatchable at that point in time, the proposed rules make resources eligible in more Real-time Settlement Intervals and, thus, capture the economic impact of a resource's behavior even when the resource is not online or dispatchable as expected.

163. An exception to the above start time rules is the rule for no soak resources that have started early compared to their pool-scheduled commitment. Unlike soak resources, the costs associated with ramping up to Economic Minimum are not already included in a no soak resource's Start-up Costs. Therefore, under the status quo process, no soak resources that start up to 30 minutes early pursuant to PJM real-time dispatch instructions may be eligible before the PJM real-time dispatch instruction start time based on a subjective review of whether the resource is ramping up at that time in order to follow PJM's dispatch instructions. If no soak resources start early for other reasons (i.e., to be online early to run as a self-scheduled resource), the resource will not be eligible before the resource's start time.

164. PJM and the Market Monitor reviewed the ramp-up times of no soak resources and found that 90% of the time, PJM resources could ramp up from offline to Economic Minimum within 20 minutes, 10 minutes later than the status quo rules allow for.[136] Thus, under the proposed rule, the pre-commitment eligibility period begins with the Real-time Settlement Interval when a no soak generation resource comes online but may not begin earlier than (20 minutes) prior to the first Real-time Settlement Interval of the pool-scheduled commitment.[137] The proposed rule does not require

[135] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e)(i).

[136] Brian Weathers, *Balancing Operating Reserve Credits – Updates for Early Eligibility and Flexible Resources*, PJM Interconnection, L.L.C., 6 (Oct. 11, 2024), https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2024/20241011-special/item-01---balancing-operating-reserve-calculation-proposed-updates.pdf.

[137] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e)(i).

a subjective check that the resource is ramping. If online prior to the first Real-time Settlement Interval of the pool-scheduled commitment, the resource will be eligible for any intervals it is online immediately preceding the start of the pool-scheduled commitment, up to 20 minutes, regardless of whether it is ramping in that period or not. The intent of this early eligibility period is to allow the resource to recover the costs of the ramping MW up to Economic Minimum in preparation for following PJM dispatch at the beginning of the commitment period, even if that ramping already happened. As such, the balancing Energy Make Whole credit calculation contains a provision that the resource will only be made whole for MW up to the resource's minimum operating limit during this period.[138] This way, if a resource completes ramping prior to the start of the commitment and is producing more than its minimum operating limit in these 20 minutes, the resource will not be made whole for any MW not desired by PJM.

165. A no soak resource's eligibility during the twenty-minute pre-commitment period is further conditioned on the resource's incremental energy offer price MW pairs remaining less than or equal to the price and MW quantities of its Incremental Energy Offer using the Committed Offer for the first hour of PJM commitment. This condition is a safeguard to prevent overpaying uplift to resources whose offers exceed those used by PJM in the initial commitment decision. For example, PJM can commit a resource with a $20/MWh offer from 10:00 until 12:00. If such resource has an offer of $200/MWh that is effective from 09:00 until 10:00, without this safeguard, PJM could end up paying uplift for any energy produced between 09:40 and 10:00 based on an offer that was never contemplated in the commitment decision.

C. Eligibility End Time

166. As I noted above, under the status quo rules, a resource's eligibility period is limited to the time in which the resource is online and dispatchable pursuant to PJM's commitment instructions.[139] Thus, a resource's eligibility period currently ends when any of the following conditions are met: a) the unit is taken over as self-

[138] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-2)(ii) ("The above Balancing Revenue and Real-time Cost calculation shall be further modified for Real-time Settlement Intervals preceding the start of the commitment for generation resource types with no soak process in the Start-up Cost, by capping the Actual MWh at the minimum operating limit for each such interval.").

[139] *Id.* section 3.2.3(e)(i); PJM Manual 28, section 5.2.1.

scheduled; b) the unit trips; or c) PJM releases the resource, then the earlier of when a resource ramps down to 0 MW or three hours.

167. Under the proposed rules, eligibility will continue until the later of: (1) the day-ahead commitment or Minimum Run Time, as applicable; or (2) the Real-time Settlement Interval when the resource is no longer running at PJM's direction because the resource has, for example, tripped, been taken over by the Market Seller, or otherwise released by PJM.[140]

168. Lengthening a resource's eligibility period to include Real-time Settlement Intervals after the resource stops running or is no longer running under the direction of PJM allows PJM to recognize the net revenue the resource would have earned if it had operated as directed by PJM for the entire commitment period rather than going offline and potentially forgoing those revenues or, in the case of the resource no longer running under the direction of PJM, excluding those revenues the resource received during this time period.

169. Resources may also be eligible for balancing Energy Make Whole credits for post-commitment Real-time Settlement Intervals until the Real-time Settlement Interval in which the resource goes offline, as further limited by "the Real-time Settlement Interval in which the resource is no longer running under the direction of [PJM] plus the number of Real-time Settlement Intervals corresponding to the allowable ramp down period for the resource type, as specified in the PJM Manuals."[141]

170. "However, a generation resource is only eligible for this post-commitment period if the price and [MW] quantities submitted as part of its Incremental Energy Offer, using the lesser of the Final Offer or Committed Offer as determined using the Actual MWh during the post-commitment period, is less than or equal to the price and [MW] quantities of its Incremental Energy Offer using the Committed Offer

[140] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e)(i) ("The generation resource remains eligible for balancing Energy Make Whole credits until the later of: 1) the Real-time Settlement Interval corresponding to the end of its Day-ahead Energy Market commitment or the end of its Minimum Run Time, as applicable or 2) the Real-time Settlement Interval when the resource is no longer running under the direction of [PJM].").

[141] *Id.* Establishing ramp down periods tailored to the resource type effectively limits post-commitment eligibility to the intervals needed for the resource type to ramp down. *See* Brian Weathers, *Operating Reserve Clarification Updates*, 4 (Mar. 11, 2024), https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2024/20240311-special/item-01---operating-reserve-clarification-methodology-updates.pdf.

for the last hour of the commitment."[142] Just as in the pre-commitment period, this condition is a safeguard against overpaying uplift to resources that have offers that exceed the offers used by PJM when deciding to commit the resource.

D. Costs/Revenues Interaction with Eligibility Rules

171. In the Real-time Settlement Intervals when resources are ramping up, real-time energy make whole payments are calculated differently depending on whether the resource is a soak or a no soak unit. The different treatment reflects the fact that ramp-up costs and the associated expected revenues of soak resources are already included in their Start-up Costs, while ramp-up costs and the associated expected revenues of no soak resources are not.

172. If a *soak* resource is ramping up to Economic Minimum in Real-time Settlement Intervals when the resource is scheduled to be dispatchable and eligible for real-time energy make whole payments, the costs incurred and/or revenues received during these Real-time Settlement Intervals are removed from Step 1 and Step 2 of the balancing Energy Make Whole credit equation.[143] This prevents double-compensation—once through Start-up Costs, and again through incremental energy costs recovered through real-time energy make whole payments for such intervals. On the other hand, as previously explained, in the twenty-minute pre-commitment period in which *no soak* resources are eligible to receive real-time energy make whole credits, PJM is proposing to cap TRLD MWh and Actual MWh at the minimum operating limit, typically Economic Minimum, for the each Real-time Settlement Interval.[144] Thus, while a *no soak* resource may be made whole for ramping up prior to commitment start, they may not be made whole above the minimum operating limit to which the resource must ramp prior to dispatch. In other words, no soak resources will not be made whole for over-producing during their ramp-up period.

V. Examples Applying the Revised Eligibility Rules and the Proposed TRLD MWh Metric and Balancing Energy Make Whole Credit Equation

173. Below, I walk through a few examples to demonstrate how the revised eligibility rules, when combined with the other proposed rules I discuss in Parts II and III of

[142] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e)(i).

[143] *Id.* sections 3.2.3(e-2)(i)-(ii).

[144] *Id.*

my affidavit, above, provide a fuller picture of the impacts of following and/or deviating from PJM's expectations on a resource's real-time energy make whole credits. As the examples show, a resource's TRLD measurement period may differ from the resource's pool-scheduled commitment period, from which the eligibility period is derived, depending on, for example, the resource's characteristics and expected and actual operation in the Real-time Energy Market. In addition, I note that PJM previously presented these examples, and numerous others, during stakeholder meetings. Thus, additional examples that show how the revised eligibility rules would work in a variety of scenarios are memorialized in publicly available presentations.[145]

174. While the below examples focus on the impact of the proposed rules on real-time energy make whole payments, it is also important to keep in mind that PJM is proposing to apply TRLD MWh to deviations, which will impact the resulting deviation charges assessed against resources that fail to perform as PJM expected.

175. To be clear, PJM is not proposing to apply the proposed real-time energy make whole payment eligibility rules to deviations. Rather, deviations will continue to be calculated in every Real-time Settlement Interval in which the resource meets a deviation threshold and is not otherwise exempt from deviation charges. Using the TRLD MWh metric to calculate deviations will enable PJM to better reflect when a resource has deviated from PJM's expectations throughout the resource's commitment period and across five-minute Real-time Settlement Intervals. Thus, just as the proposed balancing Energy Make Whole credit equation will more completely capture Costs and Revenues for purposes of determining the real-time energy make whole payments a resource should be paid, the proposal to use TRLD MWh to calculate deviations will better track the deviation charges that should be assessed when resources have not operated in accordance with PJM's expectations.

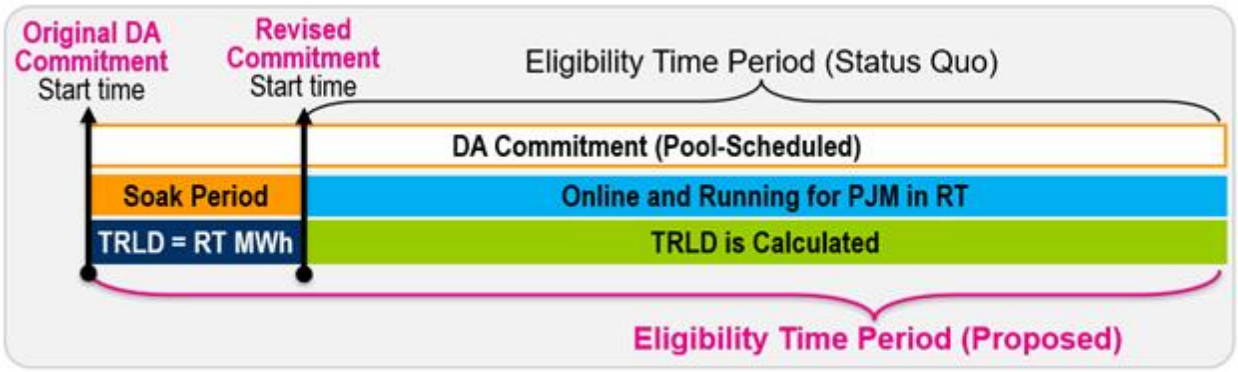
A. Example A: Soak Resource Starts Late as a Result of PJM and Thus Starts Late in Accordance with PJM's Expectations

176. In Example A, below, a soak resource is late for the start of a pool-scheduled commitment period as a result of PJM's real-time commitment instructions. The relevant facts are as follows:

---

[145] *See, e.g.*, *Consolidated BOR Credit Proposal Examples*, PJM Interconnection, L.L.C. (Dec. 9, 2024), https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2024/20241209-special/informational---consolidated-bor-credit-proposal-examples---december-2024.pdf.

- The soak resource has a pool-scheduled day-ahead commitment.
- PJM subsequently instructs the soak resource to start later, after the pool-scheduled day-ahead commitment start time.
- The soak resource complies with PJM's instructions. In real-time, the soak resource is online and dispatchable for PJM beginning in the first Real-time Settlement Interval of the later, revised start time, as instructed by PJM.
- Due to the later start, the soak resource is in its soak period prior to the revised start time during Real-time Intervals in which it has a pool-scheduled day-ahead commitment.



1. Eligibility start at first interval of pool-scheduled commitment

177. Under the status quo rules, resources are not eligible for real-time energy make whole credits until the resource is online and dispatchable during the resource's real-time pool-scheduled commitment period. In this case, the resource in Example A would not be eligible for real-time energy make whole credits until the beginning of the later start time, because the resource is not dispatchable while it is soaking.

178. Under the proposed rules, "[a] pool-scheduled generation resource's eligibility for balancing Energy Make Whole credits begins at the first Real-time Settlement Interval of a pool-scheduled commitment."[146] In this case, the first Real-time Settlement Interval in which the resource in Example A has a pool-scheduled commitment is the first interval of the pool-scheduled day-ahead commitment.

[146] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(i).

Thus, the resource's eligibility begins, under the revised rules, in the first interval of the pool-scheduled day-ahead commitment. The eligibility start time is earlier.

2. TRLD MW calculation start at revised start time

179. PJM begins calculating TRLD MW at t_0, the first Real-time Settlement Interval "when a generation resource is first expected by [PJM] to be online or when a generation resource is dispatchable, while honoring soak time differences[.]"[147] In this case, PJM expects the generation resource to be online or dispatchable at the revised start time, per PJM's instructions. Thus, t_0, when PJM begins calculating TRLD MW, is the first Real-time Settlement Interval of the revised start time.

3. Eligibility before TRLD MW calculation start

180. As described above, PJM begins measuring TRLD MW at the time when PJM expects a resource to first be online or dispatchable, while eligibility begins at the first Real-time Settlement Interval of the resource's commitment period. Therefore, in Example A, the soak resource's eligibility period begins before start time t_0, when PJM begins measuring TRLD MW.

181. In accordance with the proposed Tariff rules, before start time t_0, the resource's Actual MWh, as determined in accordance with Operating Agreement, Schedule 1, section 3.1A, will be used in place of TRLD MWh and unadjusted TRLD MWh in Step 1 of the equation "[f]or all Real-time Settlement Intervals prior to the start time of the [TRLD MW] calculation, t_0[.]"[148] Applying the above proposed rule to Example A, because the soak resource is eligible before start time t_0, the resource's Actual MWh will be used in Step 1 of the equation in place of TRLD MWh and unadjusted TRLD MWh.

4. The impact of the proposed rules on real-time energy make whole credits.

182. In Example A, the beginning of the resource's revised pool-scheduled real-time commitment period and the beginning of the TRLD MW calculation period coincide, but the eligibility period, derived from the day-ahead commitment period,

[147] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e-1)(i).

[148] *Id.* section 3.2.3(e-1)(iv).

begins earlier, i.e., before the resource is online and dispatchable and includes the resource's soak period.

183. Because the costs associated with the soak period are included in a soak resource's Start-up Costs, the proposed Tariff requires that if soak resources are ramping up to Economic Minimum in Real-time Settlement Intervals when such soak resources were scheduled to be dispatched and eligible for real-time energy make whole payments, the costs incurred and/or revenues received during these Real-time Settlement Intervals are removed from Step 1 and Step 2 of the balancing Energy Make Whole credit equation.[149] Thus, in Example A, the costs associated with the energy produced during the soak period are removed from Step 1 and Step 2 of the balancing Energy Make Whole credit equation. These costs must be removed to avoid double-counting.

184. The earlier eligibility start time under the proposed rules is an improvement over the status quo rules, because it provides a more complete picture of the resource's economics. The costs and revenues associated with the Actual MWh produced during the soak period are excluded from the equation, because those costs are already reflected in the soak resource's Start-up Costs. However, the earlier eligibility start time means that, to the extent that any additional costs and revenues accrue from buying out of the Day-ahead Energy Market, those additional costs and revenues will be reflected in both Step 1 and Step 2 of the proposed equation during the period before the revised start time. Under the status quo rules, the balancing Operating Reserve credit equation does not begin to apply until the first Real-time Settlement Interval in which the resource is online and dispatchable. Therefore, the status quo rules would not capture these additional costs and revenues. Assuming the level of DA MW the resource was committed for in the Day-ahead Energy Market is greater than the RT MW produced while the resource soaks, in this scenario, the resource will be made whole for the additional cost of buying out of the Day-ahead Energy Market, which is a cost incurred by the resource in order to perform in accordance with PJM's instructions and expectations.

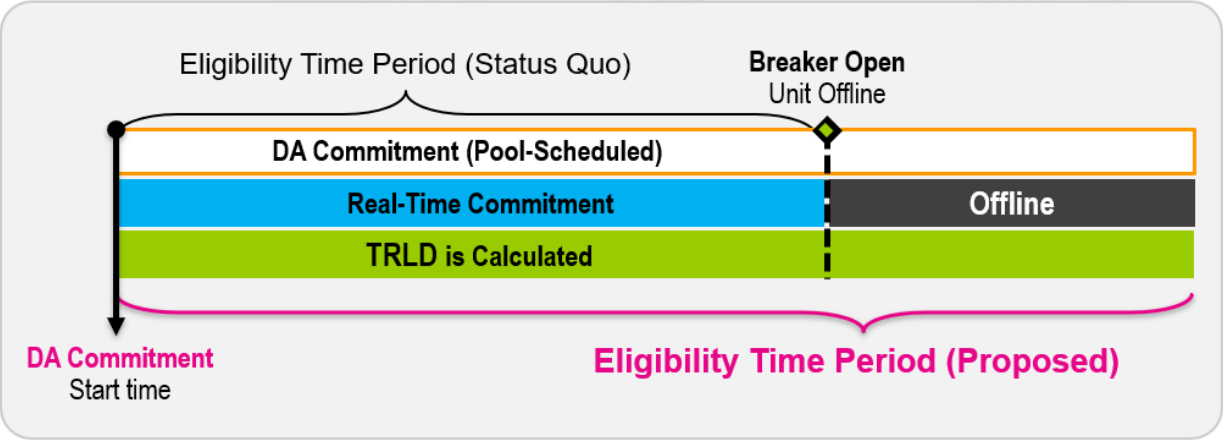
B. Example B: Resource Trips Before End of Commitment Period and Thus Does Not Perform as PJM Expected

185. In Example B, below, the resource goes offline before the end of its pool-scheduled day-ahead commitment period. The resource has tripped and, thus, is not

[149] Proposed Tariff, Attachment K-Appendix, sections 3.2.3(e-2)(i)-(ii).

performing in accordance with PJM's expectations when it goes offline early. The relevant facts are as follows:

- The resource has a pool-scheduled day-ahead commitment. The day-ahead commitment exceeds the Minimum Run Time.
- The pool-scheduled day-ahead commitment period becomes the pool-scheduled real-time commitment period.
- The resource trips and therefore goes offline before the end of its pool-scheduled commitment period.



1. Eligibility end time at end of day-ahead commitment

186. Under the status quo rules, a resource's eligibility ends when any of the following conditions are met: a) the unit is taken over as self-scheduled; b) the unit trips; or c) PJM releases the resource, then the earlier of when a resource ramps down to 0 MW or three hours.

187. In this case, the resource in Example B stops being eligible for real-time energy make whole credits once the resource has tripped. PJM does not, under the status quo rules, account for any costs or revenues the resource accrues during the remainder of the resource's pool-scheduled commitment period after the resource has gone offline.

188. Under the proposed rules, eligibility will continue until *the later of*: (1) the day-ahead commitment or Minimum Run Time, as applicable; or (2) the Real-time Settlement Interval when the resource is no longer running at PJM's direction

because the resource has, for example, tripped, been taken over by the Market Seller, or otherwise released by PJM.[150]

189. In Example B, the resource trips before the end of its day-ahead commitment, which exceeds the resource's Minimum Run Time. Because eligibility continues until *the later of* the day-ahead commitment and the Real-time Settlement Interval in which the resource is no longer running at PJM's direction, the eligibility period for the resource in Example B continues through the end of the day-ahead commitment.

2. TRLD MW calculation end time at end of day-ahead commitment

190. Under the proposed rules, if a generation resource fails to follow PJM's instructions (i.e., trips or is taken offline at the Market Seller's request) in Real-time Settlement Intervals "prior to the later of the end of the Day-ahead Energy Market commitment or the end of the Minimum Run Time,"[151] PJM will continue to apply the TRLD MW and unadjusted TRLD MW equations to Real-time Settlement Intervals "until the later of the end of the Day-ahead Energy Market commitment or the end of the Minimum Run Time."[152] In this case, PJM continues to calculate TRLD after the resource trips until the end of the resource's pool-schedules day-ahead commitment.

3. The impact of the proposed rules on real-time energy make whole credits.

191. In Example B, the resource's eligibility end time coincides with the end of the resource's pool-scheduled commitment period and the end of the TRLD MW calculation period. All three periods extend beyond the time when the resource is actually online.

192. Under the proposed rules, if a resource trips,[153] PJM will continue to apply the TRLD MW and unadjusted TRLD MW equations to Real-time Settlement Intervals "until the later of the end of the Day-ahead Energy Market commitment or the end

[150] Proposed Tariff, Attachment K-Appendix, section 3.2.3(e)(i) ("The generation resource remains eligible for balancing Energy Make Whole credits until the later of: 1) the Real-time Settlement Interval corresponding to the end of its Day-ahead Energy Market commitment or the end of its Minimum Run Time, as applicable or 2) the Real-time Settlement Interval when the resource is no longer running under the direction of [PJM].").

[151] *Id.* section 3.2.3(e-1)(iii).

[152] *Id.*

[153] *Id.*

of the Minimum Run Time."[154] In this case, PJM stops measuring TRLD MWh at the end of the resource's day-ahead commitment period. Thus, TRLD MWh allows PJM to establish where the resource would have been desired had it continued to operate consistent with the initial commitment expectation. In this case, rather than going offline (i.e., having an actual output of 0 MWh), the TRLD MWh metric would track the desired MWh that the resource would have provided had it operated in accordance with PJM's expectations.

193. In Example B, the eligibility period also ends at the end of the day-ahead commitment period. Thus, the proposed balancing Energy Make Whole credit calculation is applied in the Real-time Settlement Intervals across the day-ahead commitment period until the commitment end time. Thus, in Example B, Step 1 of the proposed balancing Energy Make Whole credit calculation, which uses TRLD MWh, reflects the costs and revenues that the resource would have accrued had it operated in accordance with PJM's expectations.

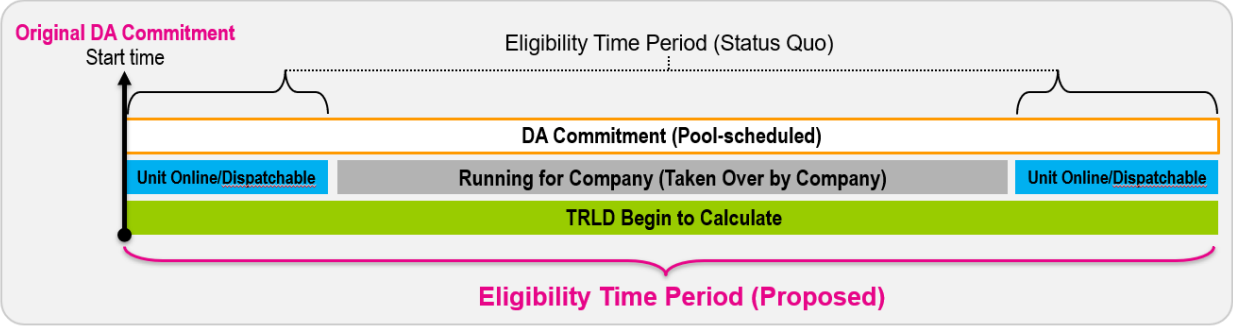
194. Relying on the TRLD metric allows PJM to continue tracking where the resource was expected to be throughout the resource's commitment period. PJM takes the expected output level into account when calculating the costs and revenues that would have been incurred in Step 1 of the balancing Energy Make Whole equation as detailed in Tariff, Attachment K-Appendix, section 3.2.3(e-2)(i). Then, in Step 2 of the equation, PJM accounts for the resource's actual output, including during the Real-time Settlement Intervals in which the resource tripped and was offline. In those intervals, the actual output is 0 MWh. To the extent the resource earned additional revenue from buying out of its day-ahead energy position at a profit, the Step 2 calculation will now recognize these additional revenues. In Step 3, PJM takes the lower of the Step 1 and Step 2 results. The difference between the resulting values in Step 1 and Step 2 show the costs and revenues that the resource forwent when it tripped before the end of its commitment period. Under the status quo rules, the resource's eligibility would have ended when the resource tripped, and the rules would therefore fail to capture any foregone costs and revenues resulting from the early stop time under step 1 and any profit (or loss) the resource earned from buying out of its day-ahead commitment in step 2.

[154] *Id.*

C. Example C: Resource Taken Over by Company and Thus Resource Does Not Perform as PJM Expected

195. In Example C, below, the resource is taken over by the company in the middle of its pool-scheduled commitment period, then returned to PJM before the end of its pool-scheduled commitment period. The relevant facts are as follows:

- The resource has a pool-scheduled day-ahead commitment. It exceeds the resource's Minimum Run Time.
- The pool-scheduled day-ahead commitment period becomes the pool-scheduled real-time commitment period.
- The resource is online and dispatchable at the beginning of the pool-scheduled commitment period, in accordance with PJM's expectations.
- In real-time, after the resource has begun running in accordance with the pool-scheduled commitment, the Market Seller takes over the resource by self-scheduling, such that the resource is running for the company and no longer for PJM.
- The Market Seller returns the resource to PJM's control before the end of the pool-scheduled commitment period, and the resource returns to running for PJM.
- The resource goes offline at the end of the pool-scheduled commitment period, in accordance with PJM's expectations.



1. Eligibility during self-schedule

196. Under the status quo rules, a resource's eligibility period is limited to the time in which the resource is online and dispatchable pursuant to PJM's commitment

instructions.[155] Thus, in this case, the resource in Example C is not eligible during the period when the resource is self-scheduled (shown here in gray). The resource is only eligible in the Real-time Settlement Intervals occurring during the resource's pool-scheduled commitment before and after the period when the resource is self-scheduled (shown here in blue).

197. Under the proposed rules, eligibility continues until the later of: (1) the day-ahead commitment or Minimum Run Time, as applicable; or (2) the Real-time Settlement Interval when the resource is no longer running at PJM's direction because the resource has, for example, tripped, been taken over by the Market Seller, or been otherwise released by PJM.[156]

198. In Example C, the day-ahead commitment exceeds the Minimum Run Time. The resource remains eligible throughout the day-ahead commitment period, including the period in which the resource was self-scheduled, until the end of the day-ahead commitment.

2. TRLD calculation during self-schedule

199. Under the proposed rules, if a generation resource fails to follow PJM's instructions (i.e., trips or is taken over to run for company at the Market Seller's request) in Real-time Settlement Intervals "prior to the later of the end of the Day-ahead Energy Market commitment or the end of the Minimum Run Time, the [TRLD] values will continue to be calculated per [the tariff calculations] until the later of the end of the Day-ahead Energy Market commitment or the end of the Minimum Run Time."[157] Thus, in this case, PJM continues to calculate TRLD even after the resource is taken over by the Market Seller, throughout the self-schedule, and until the end of the resource's pool-schedules day-ahead commitment.

[155] Tariff, Attachment K-Appendix, section 3.2.3(e)(i); PJM Manual 28, section 5.2.1.

[156] Proposed Tariff, Attachment K- Appendix, section 3.2.3(e)(i) ("The generation resource remains eligible for balancing Energy Make Whole credits until the later of: 1) the Real-time Settlement Interval corresponding to the end of its Day-ahead Energy Market commitment or the end of its Minimum Run Time, as applicable or 2) the Real-time Settlement Interval when the resource is no longer running under the direction of the Office of the Interconnection.").

[157] *Id.* section 3.2.3(e-1)(iii).

3. The impact of the proposed rules on real-time energy make whole credits.

200. In Example C, the resource's eligibility period coincides with the resource's pool-scheduled commitment period and the TRLD MWh calculation period. TRLD is calculated and the resource is eligible to receive real-time energy make whole credits throughout the commitment period, including during the period when the resource is self-scheduled.

201. Because, under the status quo rules, the resource is not eligible during the self-scheduled period, the current balancing Operating Reserve credit calculation does not capture the full impact of the resource's operations during the commitment period. Any net revenues earned while the resource is self-scheduled are excluded from the make whole credit calculation. This means any profits (or positive net revenues) the resource earns while self-scheduled would not be available to help offset the Start-up Costs that must be covered through the make whole credit calculation, which may lead to higher make whole credits than the resource otherwise would have received if it had continued operating as a pool-scheduled resource consistent with PJM's commitment decision.

202. Under the proposed rules, Step 1 of the balancing Energy Make Whole credit calculation would capture costs and revenues that the resource would have paid and earned had the resource performed as PJM expected throughout the duration of the original PJM commitment period. Step 2 would, on the other hand, capture the costs and revenues resulting from the resource's Actual MWh output for the duration of the original PJM commitment period, including the actual output during the period when the resource is self-scheduled. In this way, the proposed rules better capture all the costs and revenues during the entire commitment period that PJM considered when making the decision to commit the unit and incur the aforementioned Start-up Costs.

203. This concludes my affidavit.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) Docket No. ER26-___-000

VERIFICATION

I, Lisa Morelli, pursuant to 28 U.S.C. § 1746, state, under penalty of perjury, that I am the Lisa Morelli referred to in the foregoing "Affidavit of Senior Director of Market Settlements, Ms. Lisa Morelli and Exhibit No. Morelli-0001 on behalf of PJM Interconnection, L.L.C.," that I have read the same and am familiar with the contents thereof, and that the facts set forth therein are true and correct to the best of my knowledge, information, and belief.

/s/ Lisa Morelli
Lisa Morelli

Executed on: October 7, 2025

Incremental Energy Offer of Hyopthetical Resource			
Offer Segment	**Begin MW**	**End MW**	**Price**
1	0 MW	50 MW	$20.00
2	50 MW	75 MW	$25.00
3	75 MW	100 MW	$30.00

Day-ahead Information	
Day-ahead MWh	75 MWh
Day-ahead LMP	$28.00
Startup	$0.00
No Load	$2,000.00
DA Economic Minimum	50 MWh
DA Economic Maximum	100 MWh

Real-time Information	
Actual MWh	47 MWh
Real-time LMP	$60.00
Tracking Desired MWh	100 MWh
Unadjusted Tracking Desired MWh	100 MWh
Start-up	$-
No Load	$2,000.00
RT Economic Minimum	50 MWh
RT Economic Maximum	50 MWh

Synchronized Operating Reserve Offer Price	
Offer Price	$0

Day-ahead Synchronized Reserve Data	
DA Synchronized Reserve Assignment	25 MWh
DA Synchronized Reserve Clearing Price	$22.50

Real-time Synchronized Reserve Data	
RT Synchronized Reserve Assignment	0 MWh
RT Synchronized Reserve Clearing Price	$45.00

STEP 1 (SEGMENT 1, INTERVAL 1) Tracking Balancing Net Revenue	
DA Revenue (Day-ahead MWh * Day-ahead LMP)	**$175.00**
Balancing Revenue ((Tracking Desired MWh - Day-ahead MWh) * Real-time	$125.00
- Company Responsible Negative Revenues)	$-
	$125.00
Other Market Revenue (SR + SecR + NSR + Reactive + LOC + Reg)	
SR	($46.88)
SecR	$-
NSR	$-
Reactive	$-
LOC	$-
Reg	$-
	($46.88)
Opportunity Cost Owed	**$47.92**
Total Real-time Cost (Incremental Offer + No Load + Start-Up)	
Incremental Offer @ 100 MW	$187.50
No Load	$166.67
Start-Up	$-
	$354.17
Tracking Balancing Net Revenue (DA Revenue + Balancing Revenue + Other Market Revenue + Opportunity Cost Owed) - Real-Time Cost)	**($53.12)**

STEP 2 (SEGMENT 1, INTERVAL 1) Actual Balancing Net Revenue	
DA Revenue (Day-ahead MWh * Day-ahead LMP)	**$175.00**
Balancing Revenue ((Actual MWh - Day-ahead MWh) * Real-time LMP)	($140.00)
- Company Responsible Negative Revenues)	($66.67)
	($73.33)
Other Market Revenue (SR + SecR + NSR + Reactive + LOC + Reg)	
SR	($46.88)
SecR	$-
NSR	$-
Reactive	$-
LOC	$-
Reg	$-
	($46.88)
Total Real-time Cost (Incremental Offer + No Load + Start-Up)	
Incremental Offer @ 47 MW	$78.33
No Load	$166.67
Start-Up	$-
	$245.00
Actual Balancing Net Revenue (DA Revenue + Balancing Revenue + Other Market Revenue) - Real-Time Cost)	**($190.21)**

Real-Time Synchronized Reserve Market Potential	
Day-Ahead Clearing Price Credit	$46.88
Balancing Clearing Price Credit	($93.75)
RT Opportunity Cost	$-
Opportunity Cost Owed	$47.92
Market Revenue Neutrality	$-
Lost Opportunity Cost Credit	$-
Ancillary Service Credit	($46.88)
Ancillary Service Revenue Above	$-

Real-Time Synchronized Reserve Market Actual	
Day-Ahead Clearing Price Credit	$46.88
Balancing Clearing Price Credit	($93.75)
RT Opportunity Cost	$-
Opportunity Cost Owed	$47.92
Market Revenue Neutralitiy	$-
Lost Opportunity Cost Credit	$-
Ancillary Service Credit	($46.88)
Ancillary Service Revenue Above	$-

Incremental Energy Offer of Hyopthetical Resource			
Offer Segment	**Begin MW**	**End MW**	**Price**
1	0 MW	50 MW	$20.00
2	50 MW	75 MW	$25.00
3	75 MW	100 MW	$30.00

Day-ahead Information	
Day-ahead MWh	50 MWh
Day-ahead LMP	$32.00
Startup	$0.00
No Load	$2,000.00
DA Economic Minimum	50 MWh
DA Economic Maximum	100 MWh

Real-time Information	
Actual MWh	50 MWh
Real-time LMP	$57.00
Tracking Desired MWh	75 MWh
Unadjusted Tracking Desired MWh	100 MWh
Startup	$-
No Load	$2,000.00
RT Economic Minimum	50 MWh
RT Economic Maximum	100 MWh

Tra

STEP 1 (SEGMENT 1, INTERVAL 2) Tracking Balancing Net Revenue		
DA Revenue (Day-ahead MWh * Day-ahead LMP)		**$133.33**
Balancing Revenue ((Tracking Desired MWh - Day-ahead MWh) * Real-time		$118.75
- Company Responsible Negative Revenues)		$-
		$118.75
Other Market Revenue (SR + SecR + NSR + Reactive + LOC + Reg)		
	SR	$61.46
	SecR	$-
	NSR	$-
	Reactive	$-
	LOC	$-
	Reg	$-
		$61.46
Opportunity Cost Owed		$-
Total Real-time Cost (Incremental Offer + No Load + Start-Up)		
	Incremental Offer @ 75 MW	$130.21
	No Load	$166.67
	Start-Up	$-
		$296.88
Tracking Balancing Net Revenue (DA Revenue + Balancing Revenue + Other Market Revenue + Opportunity Cost Owed) - Real-Time Cost)		**$16.67**

STEP 2 (SEGMENT 1, INTERVAL 2) Actual Balancing Net Revenue		
DA Revenue (Day-ahead MWh * Day-ahead LMP)		**$133.33**
Balancing Revenue ((Actual MWh - Day-ahead MWh) * Real-time LMP)		$-
- Company Responsible Negative Revenues)		$-
		$-
Other Market Revenue (SR + SecR + NSR + Reactive + LOC + Reg)		
	SR	$54.17
	SecR	$-
	NSR	$-
	Reactive	$-
	LOC	$-
	Reg	$-
		$54.17
Total Real-time Cost (Incremental Offer + No Load + Start-Up)		
	Incremental Offer @ 50 MW	$83.33
	No Load	$166.67
	Start-Up	$-
		$250.00
Actual Balancing Net Revenue (DA Revenue + Balancing Revenue + Other Market Revenue) - Real-Time Cost)		**($62.50)**

Synchronized Operating Reserve Offer Price	
Offer Price	$0

Reserve Data	
DA Synchronized Reserve Assignment	0 MWh
DA Synchronized Reserve Clearing Price	$27.50

Reserve Data	
RT Synchronized Reserve Assignment	25 MWh
RT Synchronized Reserve Clearing Price	$26.00

Real-Time Synchronized Reserve Market Potential	
Day-Ahead Clearing Price Credit	$-
Balancing Clearing Price Credit	$54.17
RT Opportunity Cost	$61.46
Opportunity Cost Owed	$-
Market Revenue Neutrality	$-
Lost Opportunity Cost Credit	$7.29
Ancillary Service Credit	$61.46
Ancillary Service Revenue Above	$-

Real-Time Synchronized Reserve Market Actual	
Day-Ahead Clearing Price Credit	$-
Balancing Clearing Price Credit	$54.17
RT Opportunity Cost	$-
Opportunity Cost Owed	$-
Market Revenue Neutralitiy	$-
Lost Opportunity Cost Credit	$-
Ancillary Service Credit	$54.17
Ancillary Service Revenue Above	$54.17

Tracking Balancing Energy Make Whole Credit		
	Segment 1 Interval 1	**Segment 1 Interval 2**
Tracking Desired MW	100 MWh	75 MWh
DA Revenue (Day-ahead MWh * Day-ahead LMP)	$175.00	$133.33
Balancing Revenue (		
(Tracking Desired MWh - Day-ahead MWh) * Real-time LMP)	$125.00	$118.75
- Company Responsible Negative Revenues)	$-	$-
Balancing Revenue	$125.00	$118.75
Other Market Revenue (SR + SecR + NSR + Reactive + LOC + Reg)		
SR	($46.88)	$61.46
SecR	$-	$-
NSR	$-	$-
Reactive	$-	$-
LOC	$-	$-
Reg	$-	$-
	($46.88)	$61.46
Opportunity Cost Owed	$47.92	$-
Total Real-time Cost (Incremental Offer + No Load + Start-Up)		
Incremental Offer	$187.50	$130.21
No Load	$166.67	$166.67
Start-Up	$-	$-
	$354.17	$296.88
Tracking Balancing Net Revenue (DA Revenue + Balancing Revenue + Other Market Revenue + Opportunity Cost Owed) - Real-Time Cost)	($53.12)	$16.67

STEP 1 (SEGMENT 1)

Total Tracking Balancing Net Revenue	**Day-ahead Energy Make Whole Credit**	**Tracking Balancing Energy Make Whole Credit**
$ 36.46	$ -	**$ 36.46**

Actual Balancing Energy Make Whole Credit		
Columns	**Segment 1 Interval 1**	**Segment 1 Interval 2**
Actual MWh	47 MWh	50 MWh
DA Revenue (Day-ahead MWh * Day-ahead LMP)	$175.00	$133.33
Balancing Revenue (		
(Actual MWh - Day-ahead MWh) * Real-time LMP)	($140.00)	$-
- Company Responsible Negative Revenues)	($66.67)	$-
Balancing Revenue	($73.33)	$-
Other Market Revenue (SR + SecR + NSR + Reactive + LOC + Reg)		
SR	($46.88)	$54.17
SecR	$-	$-
NSR	$-	$-
Reactive	$-	$-
LOC	$-	$-
Reg	$-	$-
Total Other Market Revenue	($46.88)	$54.17
Incremental Offer	$78.33	$83.33
No Load	$166.67	$166.67
Start-Up	$-	$-
Total Real-time Cost (Incremental Offer + No Load + Start-Up)	$245.00	$250.00
Actual Balancing Net Revenue (DA Revenue + Balancing Revenue + Other Market Revenue) - Real-Time Cost)	($190.21)	($62.50)

STEP 2 (SEGMENT 1)

Total Actual Balancing Net Revenue	**Day-ahead Energy Make Whole Credit**	**Actual Balancing Energy Make Whole Credit**
$ 252.71	$ -	**$ 252.71**

STEP 3 (SEGMENT 1)

The minumum of the Tracking Balancing Energy Make Whole Credit and Actual Balancing Energy Make Whole Credit	
Balancing Energy Make Whole Credit	**$ 36.46**

Attachment C

Revisions to the Tariff in redlined and non-redlined format, as provided in electronic tariff filing format pursuant to Order No. 714

Revisions to the
PJM Open Access Transmission Tariff

(Marked/Redline Format)

Definitions – A - B

30-minute Reserve:

"30-minute Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within 30 minutes of a request from the Office of the Interconnection dispatcher, and is comprised of Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve.

30-minute Reserve Requirement:

"30-minute Reserve Requirement" shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone, as Secondary Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The 30-minute Reserve Requirement is calculated in accordance with the PJM Manuals. The requirement can be satisfied by any combination of Synchronized Reserve, Non Synchronized Reserve or Secondary Reserve resources.

Abnormal Condition:

"Abnormal Condition" shall mean any condition on the Interconnection Facilities which, determined in accordance with Good Utility Practice, is: (i) outside normal operating parameters such that facilities are operating outside their normal ratings or that reasonable operating limits have been exceeded; and (ii) could reasonably be expected to materially and adversely affect the safe and reliable operation of the Interconnection Facilities; but which, in any case, could reasonably be expected to result in an Emergency Condition. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not, standing alone, constitute an Abnormal Condition.

Acceleration Request:

"Acceleration Request" shall mean a request pursuant to Operating Agreement, Schedule 1, section 1.9.4A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.4A, to accelerate or reschedule a transmission outage scheduled pursuant to Operating Agreement, Schedule 1, section 1.9.2 or Operating Agreement, Schedule 1, section 1.9.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.2 or Tariff, Attachment K-Appendix, section 1.9.4.

Actual MWh

"Actual MWh" is equal to the real-time output of a resource as defined by the Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Tariff, Attachment K-Appendix, section 3.1A and parallel provisions in Operating Agreement, Schedule 1, section 3.1A.

Affected System:

"Affected System" shall mean an electric system other than the Transmission Provider's Transmission System that may be affected by a proposed interconnection or on which a proposed interconnection or addition of facilities or upgrades may require modifications or upgrades to the Transmission System.

Affected System Operator:

"Affected System Operator" shall mean an entity that operates an Affected System or, if the Affected System is under the operational control of an independent system operator or a regional transmission organization, such independent entity.

Affiliate:

"Affiliate" shall mean any two or more entities, one of which Controls the other or that are under common Control. "Control," as that term is used in this definition, shall mean the possession, directly or indirectly, of the power to direct the management or policies of an entity. Ownership of publicly-traded equity securities of another entity shall not result in Control or affiliation for purposes of the Tariff or Operating Agreement if the securities are held as an investment, the holder owns (in its name or via intermediaries) less than 10 percent (10%) of the outstanding securities of the entity, the holder does not have representation on the entity's board of directors (or equivalent managing entity) or vice versa, and the holder does not in fact exercise influence over day-to-day management decisions. Unless the contrary is demonstrated to the satisfaction of the Members Committee, Control shall be presumed to arise from the ownership of or the power to vote, directly or indirectly, ten percent or more of the voting securities of such entity.

Agreements:

"Agreements" shall mean the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., the PJM Open Access Transmission Tariff, the Reliability Assurance Agreement, and/or other agreements between PJM Interconnection, L.L.C. and its Members.

Ancillary Services:

"Ancillary Services" shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

Annual Demand Resource:

"Annual Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

Annual Energy Efficiency Resource:

"Annual Energy Efficiency Resource" shall have the meaning specified in the Reliability Assurance Agreement.

Annual Resource:

"Annual Resource" shall mean a Generation Capacity Resource, an Annual Energy Efficiency Resource or an Annual Demand Resource.

Annual Revenue Rate:

"Annual Revenue Rate" shall mean the rate employed to assess a compliance penalty charge on a Curtailment Service Provider under Tariff, Attachment DD, section 11.

Annual Transmission Costs:

"Annual Transmission Costs" shall mean the total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H for each Zone until amended by the applicable Transmission Owner or modified by the Commission.

Applicable Laws and Regulations:

"Applicable Laws and Regulations" shall mean all duly promulgated applicable federal, State and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority having jurisdiction over the relevant parties, their respective facilities, and/or the respective services they provide.

Applicable Regional Entity:

"Applicable Regional Entity" shall mean the Regional Entity for the region in which a Network Customer, Transmission Customer, New Service Customer, or Transmission Owner operates.

Applicable Standards:

"Applicable Standards" shall mean the requirements and guidelines of NERC, the Applicable Regional Entity, and the Control Area in which the Customer Facility is electrically located; the PJM Manuals; and Applicable Technical Requirements and Standards.

Applicable Technical Requirements and Standards:

"Applicable Technical Requirements and Standards" shall mean those certain technical requirements and standards applicable to interconnections of generation and/or transmission facilities with the facilities of an Interconnected Transmission Owner or, as the case may be and to the extent applicable, of an Electric Distributor, as published by Transmission Provider in a PJM Manual provided, however, that, with respect to any generation facilities with maximum generating capacity of 2 MW or less (synchronous) or 5 MW or less (inverter-based) for which the Interconnection Customer executes a Construction Service Agreement or Interconnection

Service Agreement on or after March 19, 2005, "Applicable Technical Requirements and Standards" shall refer to the "PJM Small Generator Interconnection Applicable Technical Requirements and Standards." All Applicable Technical Requirements and Standards shall be publicly available through postings on Transmission Provider's internet website.

Applicant:

"Applicant" shall mean an entity desiring to become a PJM Member, become a Market Participant, engage in market activities, or to take Transmission Service that has submitted the PJMSettlement credit application, PJMSettlement credit agreement and other required submittals as set forth in Tariff, Attachment Q.

Application:

"Application" shall mean a request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

Attachment Facilities:

"Attachment Facilities" shall mean the facilities necessary to physically connect a Customer Facility to the Transmission System or interconnected distribution facilities.

Attachment H:

"Attachment H" shall refer collectively to the Attachments to the PJM Tariff with the prefix "H" that set forth, among other things, the Annual Transmission Rates for Network Integration Transmission Service in the PJM Zones.

Auction Revenue Rights:

"Auction Revenue Rights" or "ARRs" shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Operating Agreement, Schedule 1, section 7.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.

Auction Revenue Rights Credits:

"Auction Revenue Rights Credits" shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Authorized Government Agency:

"Authorized Government Agency" means a regulatory body or government agency, with jurisdiction over PJM, the PJM Market, or any entity doing business in the PJM Market, including, but not limited to, the Commission, State Commissions, and state and federal

attorneys general.

Avoidable Cost Rate:

"Avoidable Cost Rate" shall mean a component of the Market Seller Offer Cap calculated in accordance with Tariff, Attachment DD, section 6.

Balancing Congestion Charges:

"Balancing Congestion Charges" shall be equal to the sum of congestion charges collected from Market Participants that are purchasing energy in the Real-time Energy Market minus [the sum of congestion charges paid to Market Participants that are selling energy in the Real-time Energy Market plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, plus any charges or credits calculated pursuant to Operating Agreement, Schedule 1, section 3.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 3.8, as applicable)].

Balancing Ratio:

"Balancing Ratio" shall have the meaning provided in Tariff, Attachment DD, section 10A.

Base Load Generation Resource

"Base Load Generation Resource" shall mean a Generation Capacity Resource that operates at least 90 percent of the hours that it is available to operate, as determined by the Office of the Interconnection in accordance with the PJM Manuals.

Base Offer Segment:

"Base Offer Segment" shall mean a component of a Sell Offer based on an existing Generation Capacity Resource, equal to the Unforced Capacity of such resource, as determined in accordance with the PJM Manuals. If the Sell Offers of multiple Market Sellers are based on a single Existing Generation Capacity Resource, the Base Offer Segments of such Market Sellers shall be determined pro rata based on their entitlements to Unforced Capacity from such resource.

Base Residual Auction:

"Base Residual Auction" shall mean the auction conducted three years prior to the start of the Delivery Year to secure commitments from Capacity Resources as necessary to satisfy any portion of the Unforced Capacity Obligation of the PJM Region not satisfied through Self-

Supply.

Batch Load Economic Load Response Participant Resource:

"Batch Load Economic Load Response Participant Resource" shall mean an Economic Load Response Participant Resource that has a cyclical production process such that at most times during the process it is consuming energy, but at consistent regular intervals, ordinarily for periods of less than ten minutes, it reduces its consumption of energy for its production processes to minimal or zero megawatts.

Behind The Meter Generation:

"Behind The Meter Generation" shall refer to a generation unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of the Interconnection); provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit's capacity that is designated as a Generation Capacity Resource; or (ii) in an hour, any portion of the output of such generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

Black Start Service:

"Black Start Service" shall mean the capability of generating units to start without an outside electrical supply or the demonstrated ability of a generating unit with a high operating factor (subject to Transmission Provider concurrence) to automatically remain operating at reduced levels when disconnected from the grid.

Border Yearly Charge:

"Border Yearly Charge" shall mean the yearly charge determined in accordance with Tariff, Schedule 7.

Breach:

"Breach" shall mean the failure of a party to perform or observe any material term or condition of Tariff, Part IV or Tariff, Part VI, or any agreement entered into thereunder as described in the relevant provisions of such agreement.

Breaching Party:

"Breaching Party" shall mean a party that is in Breach of Tariff, Part IV or Tariff, Part VI and/or an agreement entered into thereunder.

Business Day:

“Business Day” shall mean a day in which the Federal Reserve System is open for business and is not a scheduled PJM holiday.

Buy Bid:

“Buy Bid” shall mean a bid to buy Capacity Resources in any Incremental Auction.

Buyer-Side Market Power:

“Buyer-Side Market Power” shall mean the ability of Capacity Market Sellers with a Load Interest to suppress RPM Auction clearing prices for the overall benefit of their (and/or affiliates) portfolio of generation and load.

Definitions – E - F

Economic-based Enhancement or Expansion:

"Economic-based Enhancement or Expansion" shall have the same meaning provided in the Operating Agreement.

Economic Load Response Participant:

"Economic Load Response Participant" shall mean a Member or Special Member that qualifies under Operating Agreement, Schedule 1, section 1.5A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A, to participate in the PJM Interchange Energy Market and/or Ancillary Services markets through reductions in demand.

Economic Maximum:

"Economic Maximum" shall mean the highest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Economic Minimum:

"Economic Minimum" shall mean the lowest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Effective FTR Holder:

"Effective FTR Holder" shall mean:

(i) For an FTR Holder that is either a (a) privately held company, or (b) a municipality or electric cooperative, as defined in the Federal Power Act, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other entity that is under common ownership, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or

(ii) For an FTR Holder that is a publicly traded company including a wholly owned subsidiary of a publicly traded company, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other PJM Member has over 10% common ownership with the FTR Holder, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or

(iii) an FTR Holder together with any other PJM Member, including also any Affiliate, subsidiary or parent of such other PJM Member, with which it shares common ownership, wholly or partly, directly or indirectly, in any third entity which is a PJM Member (e.g., a joint venture).

EFORd:

"EFORd" shall have the meaning specified in the PJM Reliability Assurance Agreement.

Electrical Distance:

"Electrical Distance" shall mean, for a Generation Capacity Resource geographically located outside the metered boundaries of the PJM Region, the measure of distance, based on impedance and in accordance with the PJM Manuals, from the Generation Capacity Resource to the PJM Region.

Eligible Customer:

"Eligible Customer" shall mean:

(i) Any electric utility (including any Transmission Owner and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider or Transmission Owner offer the unbundled transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner.

(ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider or a Transmission Owner offer the transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner, is an Eligible Customer under the Tariff. As used in Tariff, Part VI, Eligible Customer shall mean only those Eligible Customers that have submitted a Completed Application.

Eligible Fast-Start Resource:

"Eligible Fast-Start Resource" shall mean a Fast-Start Resource that is eligible for the application of Integer Relaxation during the calculation of Locational Marginal Prices as set forth in Tariff, Attachment K-Appendix, section 2.2.

Emergency Action:

"Emergency Action" shall mean (1) any megawatt shortage of the Primary Reserve Requirement (as specified in the PJM Manuals) in a Reserve Zone or Reserve Sub-zone, inclusive of any adjustments to such requirement to account for system conditions, as determined by the dispatch run from the security constrained economic dispatch and where, as specified in the PJM Manuals, there is also a Voltage Reduction Warning and reduction of non-critical plant load, Manual Load Dump Warning, Maximum Generation Emergency Action, or the curtailment of

non-essential building loads and Voltage Reduction Warning that encompasses such Reserve Zone or Reserve Sub-zone or (2) anytime the Office of Interconnection identifies an emergency and issues a load shed directive, Manual Load Dump Action, Voltage Reduction Action, or deploy all resources action for an entire Reserve Zone or Reserve Sub-zone.

Emergency Condition:

"Emergency Condition" shall mean a condition or situation (i) that in the judgment of any Interconnection Party is imminently likely to endanger life or property; or (ii) that in the judgment of the Interconnected Transmission Owner or Transmission Provider is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Transmission System, the Interconnection Facilities, or the transmission systems or distribution systems to which the Transmission System is directly or indirectly connected; or (iii) that in the judgment of Interconnection Customer is imminently likely (as determined in a non-discriminatory manner) to cause damage to the Customer Facility or to the Customer Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions, provided that a Generation Interconnection Customer is not obligated by an Interconnection Service Agreement to possess black start capability. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not constitute an Emergency Condition, unless one or more of the enumerated conditions or situations identified in this definition also exists.

Emergency Load Response Program:

"Emergency Load Response Program" shall mean the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during emergency conditions, and is described in Operating Agreement, Schedule 1, section 8 and the parallel provisions of Tariff, Attachment K-Appendix, section 8.

Energy Efficiency Resource:

"Energy Efficiency Resource" shall have the meaning specified in the PJM Reliability Assurance Agreement.

Energy Make Whole

"Energy Make Whole" shall refer to energy uplift provided to make a resource whole for costs incurred as specified in Tariff, Attachment K-Appendix, section 3.2.3 and parallel provisions in Operating Agreement, Schedule 1, section 3.2.3.

Energy Market Opportunity Cost:

"Energy Market Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of available run hours due to limitations imposed on the unit by Applicable Laws and Regulations, and (b) the forecasted future Locational Marginal Price at which the generating unit could run while not

violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Energy Resource:

"Energy Resource" shall mean a Generating Facility that is not a Capacity Resource.

Energy Settlement Area:

"Energy Settlement Area" shall mean the bus or distribution of busses that represents the physical location of Network Load and by which the obligations of the Network Customer to PJM are settled.

Energy Storage Resource:

"Energy Storage Resource" shall mean a resource capable of receiving electric energy from the grid and storing it for later injection to the grid that participates in the PJM Energy, Capacity and/or Ancillary Services markets as a Market Participant. Open-Loop Hybrid Resources are not Energy Storage Resources.

Energy Storage Resource Model Participant:

"Energy Storage Resource Model Participant" shall mean an Energy Storage Resource utilizing the Energy Storage Resource Participation Model.

Energy Storage Resource Participation Model:

"Energy Storage Resource Participation Model" shall mean the participation model accepted by the Commission in Docket No. ER19-469-000.

Energy Transmission Injection Rights:

"Energy Transmission Injection Rights" shall mean the rights to schedule energy deliveries at a specified point on the Transmission System. Energy Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Deliveries scheduled using Energy Transmission Injection Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

Entity Providing Supply Services to Default Retail Service Provider:

"Entity Providing Supply Services to Default Retail Service Provider" shall mean any entity, including but not limited to a load aggregator or power marketer, providing supply services to an

electric distribution company when that electric distribution company is serving as the default retail service provider, and that enters into a contract or similar obligation with such electric distribution company to serve retail customers who have not selected a competitive retail service provider.

Environmental Laws:

"Environmental Laws" shall mean applicable Laws or Regulations relating to pollution or protection of the environment, natural resources or human health and safety.

Environmentally-Limited Resource:

"Environmentally-Limited Resource" shall mean a resource which has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited by a governmental authority to operating only during declared PJM capacity emergencies.

Equivalent Load:

"Equivalent Load" shall mean the sum of a Market Participant's net system requirements to serve its customer load in the PJM Region, if any, plus its net bilateral transactions.

Event of Default:

"Event of Default," as that term is used in Tariff, Attachment Q, shall mean a Financial Default, Credit Breach, or Credit Support Default.

Exercise of Buyer-Side Market Power:

"Exercise of Buyer-Side Market Power" shall mean anti-competitive behavior of a Capacity Market Seller with a Load Interest, or directed by an entity with a Load Interest, to uneconomically lower RPM Auction Sell Offer(s) in order to suppress RPM Auction clearing prices for the overall benefit of the Capacity Market Seller's (and/or affiliates of Capacity Market Seller) portfolio of generation and load or that of the directing entity with a Load Interest as determined pursuant to Tariff, Attachment DD, section 5.14(h-2)(2)(B). A bilateral contract between the Capacity Market Seller and an entity with a Load Interest with the express purpose of lowering capacity market clearing prices shall be evidence of the Exercise of Buyer-Side Market Power.

Existing Generation Capacity Resource:

"Existing Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

Export Credit Exposure:

"Export Credit Exposure" is determined for each Market Participant for a given Operating Day, and shall mean the sum of credit exposures for the Market Participant's Export Transactions for that Operating Day and for the preceding Operating Day.

Export Nodal Reference Price:

"Export Nodal Reference Price" at each location is the 97th percentile, shall be, the real-time hourly integrated price experienced over the corresponding two-month period in the preceding calendar year, calculated separately for peak and off-peak time periods. The two-month time periods used in this calculation shall be January and February, March and April, May and June, July and August, September and October, and November and December.

Export Transaction:

"Export Transaction" shall be a transaction by a Market Participant that results in the transfer of energy from within the PJM Control Area to outside the PJM Control Area. Coordinated External Transactions that result in the transfer of energy from the PJM Control Area to an adjacent Control Area are one form of Export Transaction.

Export Transaction Price Factor:

"Export Transaction Price Factor" for a prospective time interval shall be the greater of (i) PJM's forecast price for the time interval, if available, or (ii) the Export Nodal Reference Price, but shall not exceed the Export Transaction's dispatch ceiling price cap, if any, for that time interval. The Export Transaction Price Factor for a past time interval shall be calculated in the same manner as for a prospective time interval, except that the Export Transaction Price Factor may use a tentative or final settlement price, as available. If an Export Nodal Reference Price is not available for a particular time interval, PJM may use an Export Transaction Price Factor for that time interval based on an appropriate alternate reference price.

Export Transaction Screening:

"Export Transaction Screening" shall be the process PJM uses to review the Export Credit Exposure of Export Transactions against the Credit Available for Export Transactions, and deny or curtail all or a portion of an Export Transaction, if the credit required for such transactions is greater than the credit available for the transactions.

Export Transactions Net Activity:

"Export Transactions Net Activity" shall mean the aggregate net total, resulting from Export Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Operating Agreement, Schedule 1 and the parallel provisions of Tariff, Attachment K-Appendix. Export Transactions Net Activity may be positive or negative.

Extended Primary Reserve Requirement:

"Extended Primary Reserve Requirement" shall equal the Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

Extended Synchronized Reserve Requirement:

"Extended Synchronized Reserve Requirement" shall equal the Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

Extended 30-minute Reserve Requirement:

"Extended 30-minute Reserve Requirement" shall equal the 30-minute Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended 30-minute Reserve Requirement is calculated in accordance with the PJM Manuals.

External Market Buyer:

"External Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for consumption by end-users outside the PJM Region, or for load in the PJM Region that is not served by Network Transmission Service.

External Resource:

"External Resource" shall mean a generation resource located outside the metered boundaries of the PJM Region.

Facilities Study:

"Facilities Study" shall be an engineering study conducted by the Transmission Provider (in coordination with the affected Transmission Owner(s)) to: (1) determine the required modifications to the Transmission Provider's Transmission System necessary to implement the conclusions of the System Impact Study; and (2) complete any additional studies or analyses documented in the System Impact Study or required by PJM Manuals, and determine the required modifications to the Transmission Provider's Transmission System based on the conclusions of such additional studies. The Facilities Study shall include the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service or to accommodate a New Service Request. As used in the Interconnection Service Agreement or Construction Service Agreement, Facilities Study shall mean that certain Facilities Study conducted by Transmission Provider (or at its direction) to determine the design and specification of the Customer Funded Upgrades necessary to accommodate the New Service Customer's New Service Request in accordance with Tariff, Part VI, section 207.

Fast-Start Resource:

"Fast-Start Resource" shall have the meaning set forth in Tariff, Attachment K-Appendix, section 2.2A

Federal Power Act:

"Federal Power Act" shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a, et seq.

FERC or Commission:

"FERC" or "Commission" shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over the Tariff, Operating Agreement and Reliability Assurance Agreement.

FERC Market Rules:

"FERC Market Rules" mean the market behavior rules and the prohibition against electric energy market manipulation codified by the Commission in its Rules and Regulations at 18 CFR §§ 1c.2 and 35.37, respectively; the Commission-approved PJM Market Rules and any related proscriptions or any successor rules that the Commission from time to time may issue, approve or otherwise establish.

Final Offer:

"Final Offer" shall mean the offer on which a resource was dispatched by the Office of the Interconnection for a particular clock hour for the Operating Day.

Final RTO Unforced Capacity Obligation:

"Final RTO Unforced Capacity Obligation" shall mean the capacity obligation for the PJM Region, determined in accordance with RAA, Schedule 8.

Financial Close:

"Financial Close" shall mean the Capacity Market Seller has demonstrated that the Capacity Market Seller or its agent has completed the act of executing the material contracts and/or other documents necessary to (1) authorize construction of the project and (2) establish the necessary funding for the project under the control of an independent third-party entity. A sworn, notarized certification of an independent engineer certifying to such facts, and that the engineer has personal knowledge of, or has engaged in a diligent inquiry to determine, such facts, shall be sufficient to make such demonstration. For resources that do not have external financing, Financial Close shall mean the project has full funding available, and that the project has been duly authorized to proceed with full construction of the material portions of the project by the appropriate governing body of the company funding such project. A sworn, notarized

certification by an officer of such company certifying to such facts, and that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, such facts, shall be sufficient to make such demonstration.

Financial Default:

"Financial Default" shall mean (a) the failure of a Member or Transmission Customer to make any payment for obligations under the Agreements when due, including but not limited to an invoice payment that has not been cured or remedied after notice has been given and any cure period has elapsed, (b) a bankruptcy proceeding filed by a Member, Transmission Customer or its Guarantor, or filed against a Member, Transmission Customer or its Guarantor and to which the Member, Transmission Customer or Guarantor, as applicable, acquiesces or that is not dismissed within 60 days, (c) a Member, Transmission Customer or its Guarantor, if any, is unable to meet its financial obligations as they become due, or (d) a Merger Without Assumption occurs in respect of the Member, Transmission Customer or any Guarantor of such Member or Transmission Customer.

Financial Transmission Right:

"Financial Transmission Right" or "FTR" shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2.

Financial Transmission Right Obligation:

"Financial Transmission Right Obligation" shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(b), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(b).

Financial Transmission Right Option:

"Financial Transmission Right Option" shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(c), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(c).

Firm Point-To-Point Transmission Service:

"Firm Point-To-Point Transmission Service" shall mean Transmission Service under the Tariff, Part II, section 13 that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Tariff, Part II.

Firm Transmission Feasibility Study:

"Firm Transmission Feasibility Study" shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part II, section 19.3 and Tariff, Part III, section 32.3.

Firm Transmission Withdrawal Rights:

"Firm Transmission Withdrawal Rights" shall mean the rights to schedule energy and capacity withdrawals from a Point of Interconnection of a Merchant Transmission Facility with the Transmission System. Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System with another control area. Withdrawals scheduled using Firm Transmission Withdrawal Rights have rights similar to those under Firm Point-to-Point Transmission Service.

First Incremental Auction:

"First Incremental Auction" shall mean an Incremental Auction conducted 20 months prior to the start of the Delivery Year to which it relates.

Flexible Resource:

"Flexible Resource" shall mean a generating resource that must have a combined Start-up Time and Notification Time of less than or equal to two hours; and a Minimum Run Time of less than or equal to two hours.

Forecast Pool Requirement:

"Forecast Pool Requirement" shall have the meaning specified in the Reliability Assurance Agreement.

Foreign Guaranty:

"Foreign Guaranty" shall mean a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in a foreign country, and meets all of the provisions of Tariff, Attachment Q.

Form 715 Planning Criteria:

"Form 715 Planning Criteria" shall have the same meaning provided in the Operating Agreement.

Forward Daily Natural Gas Prices:

"Forward Daily Natural Gas Prices" shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(E).

Forward Hourly Ancillary Services Prices:

"Forward Hourly Ancillary Services Prices" shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(D).

Forward Hourly LMPs:

"Forward Hourly LMPs" shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(C).

FTR Credit Limit:

"FTR Credit Limit" shall mean the amount of credit established with PJMSettlement that an FTR Participant has specifically designated to be used for FTR activity in a specific customer account. Any such credit so set aside shall not be considered available to satisfy any other credit requirement the FTR Participant may have with PJMSettlement.

FTR Credit Requirement:

"FTR Credit Requirement" shall mean the amount of credit that a Participant must provide in order to support the FTR positions that it holds and/or for which it is bidding. The FTR Credit Requirement shall not include months for which the invoicing has already been completed, provided that PJMSettlement shall have up to two Business Days following the date of the invoice completion to make such adjustments in its credit systems. FTR Credit Requirements are calculated and applied separately for each separate customer account.

FTR Flow Undiversified:

"FTR Flow Undiversified" shall have the meaning established in Tariff, Attachment Q, section VI.C.6.

FTR Historical Value:

For each FTR for each month, "FTR Historical Value" shall mean the weighted average of historical values over three years for the FTR path using the following weightings: 50% - most recent year; 30% - second year; 20% - third year.

FTR Holder:

"FTR Holder" shall mean the PJM Member that has acquired and possesses an FTR.

FTR Monthly Credit Requirement Contribution:

For each FTR, for each month, "FTR Monthly Credit Requirement Contribution" shall mean the total FTR cost for the month, prorated on a daily basis, less the FTR Historical Value for the month. For cleared FTRs, this contribution may be negative; prior to clearing, FTRs with negative contribution shall be deemed to have zero contribution.

FTR Net Activity:

"FTR Net Activity" shall mean the aggregate net value of the billing line items for auction revenue rights credits, FTR auction charges, FTR auction credits, and FTR congestion credits, and shall also include day-ahead and balancing/real-time congestion charges up to a maximum

net value of the sum of the foregoing auction revenue rights credits, FTR auction charges, FTR auction credits and FTR congestion credits.

FTR Participant:

"FTR Participant" shall mean any Market Participant that provides or is required to provide Collateral in order to participate in PJM's FTR market.

FTR Portfolio Auction Value:

"FTR Portfolio Auction Value" shall mean for each customer account of a Market Participant, the sum, calculated on a monthly basis, across all FTRs, of the FTR price times the FTR volume in MW.

Fuel Cost Policy:

"Fuel Cost Policy" shall mean the document provided by a Market Seller to PJM and the Market Monitoring Unit in accordance with PJM Manual 15 and Operating Agreement, Schedule 2, which documents the Market Seller's method used to price fuel for calculation of the Market Seller's cost-based offers for a generation resource.

Full Notice to Proceed:

"Full Notice to Proceed" shall mean that all material third party contractors have been given the notice to proceed with construction by the Capacity Market Seller or its agent, with a guaranteed completion date backed by liquidated damages.

Definitions – T – U - V

Tangible Net Worth:

"Tangible Net Worth" shall mean total assets less goodwill and other intangible assets, minus total liabilities.

Target Allocation:

"Target Allocation" shall mean the allocation of Transmission Congestion Credits as set forth in Operating Agreement, Schedule 1, section 5.2.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.3, or the allocation of Auction Revenue Rights Credits as set forth in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Third Incremental Auction:

"Third Incremental Auction" shall mean an Incremental Auction conducted three months before the Delivery Year to which it relates.

Third-Party Sale:

"Third-Party Sale" shall mean any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service but not including a sale of energy through the PJM Interchange Energy Market established under the PJM Operating Agreement.

Tie Line:

"Tie Line" shall mean a circuit connecting two balancing authority areas, Control Areas or fully metered electric system regions. Tie Lines may be classified as external or internal as set forth in the PJM Manuals.

Total Lost Opportunity Cost Offer:

"Total Lost Opportunity Cost Offer" shall mean the applicable offer used to calculate lost opportunity cost credits. For pool-scheduled resources specified in PJM Operating Agreement, Schedule 1, section 3.2.3(f-1), and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-1), the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the greater of the Committed Offer or last Real-Time Offer submitted for the offer on which the resource was committed in the Day-ahead Energy Market for each hour in an Operating Day. For all other pool-scheduled resources, the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the offer curve associated with the greater of the Committed Offer or Final Offer for each hour in an Operating Day. For self-scheduled generation resources, the

Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, where for self-scheduled generation resources (a) operating pursuant to a cost-based offer, the applicable offer curve shall be the greater of the originally submitted cost-based offer or the cost-based offer that the resource was dispatched on in real-time; or (b) operating pursuant to a market-based offer, the applicable offer curve shall be determined in accordance with the following process: (1) select the greater of the cost-based day-ahead offer and updated cost-based Real-time Offer; (2) for resources with multiple cost-based offers, first, for each cost-based offer select the greater of the day-ahead offer and updated Real-time Offer, and then select the lesser of the resulting cost-based offers; and (3) compare the offer selected in (1), or for resources with multiple cost-based offers the offer selected in (2), with the market-based day-ahead offer and the market-based Real-time Offer and select the highest offer.

Total Net Obligation:

"Total Net Obligation" shall mean all unpaid billed Net Obligations plus any unbilled Net Obligation incurred to date, as determined by PJMSettlement on a daily basis, plus any other Obligations owed to PJMSettlement at the time.

Total Net Sell Position:

"Total Net Sell Position" shall mean all unpaid billed Net Sell Positions plus any unbilled Net Sell Positions accrued to date, as determined by PJMSettlement on a daily basis.

~~**Total Operating Reserve Offer**:~~

~~"Total Operating Reserve Offer" shall mean the applicable offer used to calculate Operating Reserve credits. The Total Operating Reserve Offer shall equal the sum of all individual Real-time Settlement Interval energy offers, inclusive of Start-Up Costs (shut-down costs for Demand Resources) and No-load Costs, for every Real-time Settlement Interval in a Segment, integrated under the applicable offer curve up to the applicable megawatt output as further described in the PJM Manuals. The applicable offer used to calculate day-ahead Operating Reserve credits shall be the Committed Offer, and the applicable offer used to calculate balancing Operating Reserve credits shall be lesser of the Committed Offer or Final Offer for each hour in an Operating Day.~~

Tracking Ramp Limited Desired

"Tracking Ramp Limited Desired" shall mean the desired MW or MWh calculated pursuant to Tariff, Attachment K-Appendix, section 3.2.3(e-1) and parallel provisions in Operating Agreement, Schedule 1, section 3.2.3(e-1).

Trade Reference:

"Trade Reference" shall mean a reference from a contact or firm that had or has a material business relationship with a Participant.

Transmission Congestion Charge:

"Transmission Congestion Charge" shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses which shall be calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.1 and the parallel provisions of Tariff, Attachment K-Appendix, section 5.1.

Transmission Congestion Credit:

"Transmission Congestion Credit" shall mean the allocated share of total Transmission Congestion Charges credited to each FTR Holder, calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.2, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.

Transmission Constraint Penalty Factor:

"Transmission Constraint Penalty Factor" shall mean the maximum cost of the re-dispatch incurred to control the flows across a transmission constraint and establishes the maximum limit on the Marginal Value.

Transmission Customer:

"Transmission Customer" shall mean any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission a proposed unexecuted Service Agreement, to receive transmission service under Tariff, Part II. This term is used in Tariff, Part I and Tariff, Part VI to include customers receiving transmission service under Tariff, Part II and Tariff, Part III.

Where used in Tariff, Attachment K-Appendix and the parallel provisions of Operating Agreement, Schedule 1, Transmission Customer shall mean an entity using Point-to-Point Transmission Service.

Transmission Facilities:

"Transmission Facilities" shall have the meaning set forth in the Operating Agreement.

Transmission Forced Outage:

"Transmission Forced Outage" shall mean an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the PJM Manuals. A removal from service of a transmission facility at the request of the Office of the Interconnection to improve transmission capability shall not constitute a Forced Transmission Outage.

Transmission Injection Rights:

"Transmission Injection Rights" shall mean Capacity Transmission Injection Rights and Energy Transmission Injection Rights.

Transmission Interconnection Customer:

"Transmission Interconnection Customer" shall mean an entity that submits an Interconnection Request to interconnect or add Merchant Transmission Facilities to the Transmission System or to increase the capacity of Merchant Transmission Facilities interconnected with the Transmission System in the PJM Region or an entity that submits an Upgrade Request for Merchant Network Upgrades (including accelerating the construction of any transmission enhancement or expansion, other than Merchant Transmission Facilities, that is included in the Regional Transmission Expansion Plan prepared pursuant to Operating Agreement, Schedule 6).

Transmission Interconnection Facilities Study:

"Transmission Interconnection Facilities Study" shall mean a Facilities Study related to a Transmission Interconnection Request.

Transmission Interconnection Feasibility Study:

"Transmission Interconnection Feasibility Study" shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part IV, section 36.2.

Transmission Interconnection Request:

"Transmission Interconnection Request" shall mean a request by a Transmission Interconnection Customer pursuant to Tariff, Part IV to interconnect or add Merchant Transmission Facilities to the Transmission System or to increase the capacity of existing Merchant Transmission Facilities interconnected with the Transmission System in the PJM Region.

Transmission Loading Relief:

"Transmission Loading Relief" shall mean NERC's procedures for preventing operating security limit violations, as implemented by PJM as the security coordinator responsible for maintaining transmission security for the PJM Region.

Transmission Loss Charge:

"Transmission Loss Charge" shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Operating Agreement, Schedule 1, section 5, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.

Transmission Owner:

"Transmission Owner" shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

Transmission Owner Attachment Facilities:

"Transmission Owner Attachment Facilities" shall mean that portion of the Transmission Owner Interconnection Facilities comprised of all Attachment Facilities on the Interconnected Transmission Owner's side of the Point of Interconnection.

Transmission Owner Interconnection Facilities:

"Transmission Owner Interconnection Facilities" shall mean all Interconnection Facilities that are not Customer Interconnection Facilities and that, after the transfer under Tariff, Attachment P, Appendix 2, section 5.5 to the Interconnected Transmission Owner of title to any Transmission Owner Interconnection Facilities that the Interconnection Customer constructed, are owned, controlled, operated and maintained by the Interconnected Transmission Owner on the Interconnected Transmission Owner's side of the Point of Interconnection identified in appendices to the Interconnection Service Agreement and to the Interconnection Construction Service Agreement, including any modifications, additions or upgrades made to such facilities and equipment, that are necessary to physically and electrically interconnect the Customer Facility with the Transmission System or interconnected distribution facilities.

Transmission Owner Upgrade:

"Transmission Owner Upgrade" shall have the same meaning provided in the Operating Agreement.

Transmission Planned Outage:

"Transmission Planned Outage" shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in Operating Agreement, Schedule 1, and the parallel provisions of Tariff, Attachment K-Appendix or the PJM Manuals.

Transmission Provider:

The "Transmission Provider" shall be the Office of the Interconnection for all purposes, provided that the Transmission Owners will have the responsibility for the following specified activities:

(a) The Office of the Interconnection shall direct the operation and coordinate the maintenance of the Transmission System, except that the Transmission Owners will continue to direct the operation and maintenance of those transmission facilities that are not listed in the PJM Designated Facilities List contained in the PJM Manual on Transmission Operations;

(b) Each Transmission Owner shall physically operate and maintain all of the facilities that it owns; and

(c) When studies conducted by the Office of the Interconnection indicate that enhancements or modifications to the Transmission System are necessary, the Transmission Owners shall have the responsibility, in accordance with the applicable terms of the Tariff, Operating Agreement and/or the Consolidated Transmission Owners Agreement to construct, own, and finance the needed facilities or enhancements or modifications to facilities.

Transmission Provider's Monthly Transmission System Peak:

"Transmission Provider's Monthly Transmission System Peak" shall mean the maximum firm usage of the Transmission Provider's Transmission System in a calendar month.

Transmission Service:

"Transmission Service" shall mean Point-To-Point Transmission Service provided under Tariff, Part II on a firm and non-firm basis.

Transmission Service Request:

"Transmission Service Request" shall mean a request for Firm Point-To-Point Transmission Service or a request for Network Integration Transmission Service.

Transmission System:

"Transmission System" shall mean the facilities controlled or operated by the Transmission Provider within the PJM Region that are used to provide transmission service under Tariff, Part II and Part III.

Transmission Withdrawal Rights:

"Transmission Withdrawal Rights" shall mean Firm Transmission Withdrawal Rights and Non-Firm Transmission Withdrawal Rights.

Turn Down Ratio:

"Turn Down Ratio" shall mean the ratio of a generating unit's economic maximum megawatts to its economic minimum megawatts.

Unconstrained LDA Group:

"Unconstrained LDA Group" shall mean a combined group of LDAs that form an electrically contiguous area and for which a separate Variable Resource Requirement Curve has not been established under Tariff, Attachment DD, section 5.10. Any LDA for which a separate Variable

Resource Requirement Curve has not been established under Tariff, Attachment DD, section 5.10 shall be combined with all other such LDAs that form an electrically contiguous area.

Unforced Capacity:

"Unforced Capacity" shall have the meaning specified in the Reliability Assurance Agreement.

Unsecured Credit:

"Unsecured Credit" shall mean any credit granted by PJMSettlement to a Participant that is not secured by Collateral.

Unsecured Credit Allowance:

"Unsecured Credit Allowance" shall mean Unsecured Credit extended by PJMSettlement in an amount determined by PJMSettlement's evaluation of the creditworthiness of a Participant. This is also defined as the amount of credit that a Participant qualifies for based on the strength of its own financial condition without having to provide Collateral. See also: "Working Credit Limit."

Updated VRR Curve:

"Updated VRR Curve" shall mean the Variable Resource Requirement Curve for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect any change in the Reliability Requirement from the Base Residual Auction to such Incremental Auction.

Updated VRR Curve Decrement:

"Updated VRR Curve Decrement" shall mean the portion of the Updated VRR Curve to the left of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year and adjusted, if applicable, by a change in Unforced Capacity commitments associated with Tariff, Attachment DD, section 5.5A(c)(i)(B), and RAA, Schedule 6, section L.9.

Updated VRR Curve Increment:

"Updated VRR Curve Increment" shall mean the portion of the Updated VRR Curve to the right of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year and adjusted, if applicable, by a change in Unforced Capacity commitments associated with Tariff, Attachment DD, section 5.5A(c)(i)(B), and RAA, Schedule 6, section L.9.

Upgrade Construction Service Agreement:

"Upgrade Construction Service Agreement" shall mean that agreement entered into by an Eligible Customer, Upgrade Customer or Interconnection Customer proposing Merchant

Network Upgrades, a Transmission Owner, and the Transmission Provider, pursuant to Tariff, Part VI, Subpart B, and in the form set forth in Tariff, Attachment GG.

Upgrade Customer:

"Upgrade Customer" shall mean a customer that submits an Upgrade Request pursuant to Operating Agreement, Schedule 1, section 7.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.8.

Upgrade Feasibility Study:

"Upgrade Feasibility Study" shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part IV, section 36.3.

Upgrade-Related Rights:

"Upgrade-Related Rights" shall mean Incremental Auction Revenue Rights, Incremental Available Transfer Capability Revenue Rights, Incremental Deliverability Rights, and Incremental Capacity Transfer Rights.

Upgrade Request:

"Upgrade Request" shall mean a request submitted in the form prescribed in Tariff, Attachment EE, for evaluation by the Transmission Provider of the feasibility and estimated costs of (a) a Merchant Network Upgrade or (b) the Customer-Funded Upgrades that would be needed to provide Incremental Auction Revenue Rights specified in a request pursuant to Operating Agreement, Schedule 1, section 7.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.8.

Up-to Congestion Counterflow Transaction:

"Up-to Congestion Counterflow Transaction" shall mean an Up-to Congestion Transaction will be deemed an Up-to Congestion Counterflow Transaction if the following value is negative: (a) when bidding, the lower of the bid price and the prior Up-to Congestion Historical Month's average real-time value for the transaction; or (b) for cleared Virtual Transactions, the cleared day-ahead price of the Virtual Transactions.

Up-to Congestion Historical Month:

"Up-to Congestion Historical Month" shall mean a consistently-defined historical period nominally one month long that is as close to a calendar month as PJM determines is practical.

Up-to Congestion Prevailing Flow Transaction:

An Up-to Congestion Transaction shall mean an "Up-to Congestion Prevailing Flow Transaction" if it is not an Up-to Congestion Counterflow Transaction.

Up-to Congestion Reference Price:

"Up-to Congestion Reference Price" for an Up-to Congestion Transaction, shall be the specified percentile price differential between source and sink (defined as sink price minus source price) for real-time prices experienced over the prior Up-to Congestion Historical Month, averaged with the same percentile value calculated for the second prior Up-to Congestion Historical Month. Up-to Congestion Reference Prices shall be calculated using the following historical percentiles:

For Up-to Congestion Prevailing Flow Transactions: 30th percentile
For Up-to Congestion Counterflow Transactions when bid: 20th percentile
For Up-to Congestion Counterflow Transactions when cleared: 5th percentile

Up-to Congestion Transaction:

"Up-to Congestion Transaction" shall have the meaning specified in Operating Agreement, Schedule 1, section 1.10.1A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1A.

Variable Loads:

"Variable Loads" shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.6.

Variable Resource Requirement Curve:

"Variable Resource Requirement Curve" shall mean a series of maximum prices that can be cleared in a Base Residual Auction for Unforced Capacity, corresponding to a series of varying resource requirements based on varying installed reserve margins, as determined by the Office of the Interconnection for the PJM Region and for certain Locational Deliverability Areas in accordance with the methodology provided in Tariff, Attachment DD, section 5.

Virtual Credit Exposure:
"Virtual Credit Exposure" shall mean the amount of potential credit exposure created by a market participant's bid submitted into the Day-ahead market, as defined in Tariff, Attachment Q.

Virtual Transaction:

"Virtual Transaction" shall mean a Decrement Bid, Increment Offer and/or Up-to Congestion Transaction.

Virtual Transaction Screening:

"Virtual Transaction Screening" shall be the process of reviewing the Virtual Credit Exposure of submitted Virtual Transactions against the Credit Available for Virtual Transactions. If the credit required is greater than credit available, then the Virtual Transactions will not be accepted.

Virtual Transactions Net Activity:

"Virtual Transactions Net Activity" shall mean the aggregate net total, resulting from Virtual Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Tariff, Attachment K-Appendix, and the parallel provisions of Operating Agreement, Schedule 1. Virtual Transactions Net Activity may be positive or negative.

Voltage Reduction Action:

"Voltage Reduction Action" shall mean a notification during capacity deficient conditions in which PJM notifies Members to reduce voltage on the distribution system in order to reduce demand and therefore provide a sufficient amount of reserves, maintain tie flow schedules and preserve limited energy sources.

Voltage Reduction Alert:

"Voltage Reduction Alert" shall mean a notification from PJM to alert Members that a voltage reduction may be required during a future critical period.

Voltage Reduction Warning:

"Voltage Reduction Warning" shall mean a notification from PJM to warn Members that PJM's available Synchronized Reserve is less than the Synchronized Reserve Requirement and that present operations have deteriorated such that a voltage reduction may be required.

1.10 Scheduling.

1.10.1 General.

(a) The Office of the Interconnection shall administer scheduling processes to implement a Day-ahead Energy Market and a Real-time Energy Market. PJMSettlement shall be the Counterparty to the purchases and sales of energy that clear the Day-ahead Energy Market and the Real-time Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a Generating Market Buyer's self-schedule or self-supply of its generation resources up to that Generating Market Buyer's Equivalent Load.

(b) The Day-ahead Energy Market shall enable Market Participants to purchase and sell energy through the PJM Interchange Energy Market at Day-ahead Prices and enable Transmission Customers to reserve transmission service with Transmission Congestion Charges and Transmission Loss Charges based on locational differences in Day-ahead Prices. Up-to Congestion Transactions submitted in the Day-ahead Energy Market shall not require transmission service and Transmission Customers shall not reserve transmission service for such Up-to Congestion Transactions. Market Participants whose purchases and sales, and Transmission Customers whose transmission uses are scheduled in the Day-ahead Energy Market, shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, at the applicable Day-ahead Prices for the amounts scheduled.

(c) (i) In the Real-time Energy Market, Market Participants that deviate from the amounts of energy purchases or sales scheduled in the Day-ahead Energy Market shall be obligated to purchase or sell energy for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(ii) In the Real-time Energy Market, Transmission Customers that deviate from the transmission uses, scheduled in the Day-ahead Energy Market shall be obligated to pay Transmission Congestion Charges and Transmission Loss Charges for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(iii) Market Participants that deviate in real-time from the amounts of Secondary Reserve, Non-Synchronized Reserve, or Synchronized Reserve sales, scheduled day-ahead shall be obligated to purchase Secondary Reserve, Non-Synchronized Reserve, or Synchronized Reserve for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of

conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling does not encompass Coordinated External Transactions, which are subject to the procedures of Tariff, Attachment K-Appendix, section 1.13. Scheduling shall be conducted as specified in section 1.10.1A below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM Manuals. Such resources committed by the Office of the Interconnection to alleviate or mitigate an Emergency will not receive ~~Operating Reserve~~energy uplift Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Tariff, Attachment K-Appendix, section 3.2.3 and Tariff, Attachment K-Appendix, section 6.6.

(e) To the extent that Tariff, Attachment K-Appendix, sections 3.2.3A, 3.2.3A.001, and 3.2.3A.01 and the parallel provision of Operating Agreement, Schedule 1, sections 3.2.3A, 3.2.3A.001, and 3.2.3A.01 does not meet the Minimum Synchronized Reserve Requirement, the Minimum Primary Reserve Requirement, and the Minimum 30-minute Reserve Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Tariff, Attachment K-Appendix, section 1.7.17 and the parallel provision of Operating Agreement, Schedule 1, section 1.7.17, and Tariff, Attachment K-Appendix, section 1.10 and the parallel provision of Operating Agreement, Schedule 1, section 1.10. In addition, the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the day-ahead market.

1.10.1A Day-ahead and Real-time Energy Market Scheduling.

The following actions shall occur not later than 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the Office of the Interconnection in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Schedule.

(a) Each Market Participant may submit to the Office of the Interconnection specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the PJM Manuals. Each Market Buyer shall inform the Office of the Interconnection of the prices, if any, at which it desires not to include its load in the Day-ahead Energy Market rather than pay the Day-ahead Price. PRD Providers that have committed Price Responsive Demand in accordance with the Reliability Assurance Agreement shall submit to the Office of the Interconnection, in accordance with procedures specified in the PJM Manuals, any desired updates to their previously submitted PRD Curves, provided that such updates are consistent with their Price Responsive Demand

commitments, and provided further that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue may only submit PRD Curves for the Real-time Energy Market. Price Responsive Demand that has been committed in accordance with the Reliability Assurance Agreement shall be presumed available for the next Operating Day in accordance with the most recently submitted PRD Curve unless the PRD Curve is updated to indicate otherwise. PRD Providers may also submit PRD Curves for any Price Responsive Demand that is not committed in accordance with the Reliability Assurance Agreement; provided that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue may only submit PRD Curves for the Real-time Energy Market. All PRD Curves shall be on a PRD Substation basis, and shall specify the maximum time period required to implement load reductions.

(b) Each Generating Market Buyer shall submit to the Office of the Interconnection: (i) hourly schedules for resource increments, including hydropower units, self-scheduled by the Market Buyer to meet its Equivalent Load; and (ii) the Dispatch Rate at which each such self-scheduled resource will disconnect or reduce output, or confirmation of the Market Buyer's intent not to reduce output.

(c) All Market Participants shall submit to the Office of the Interconnection schedules for any energy exports, energy imports, and wheel through transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection if the transaction is to be scheduled in the Day-ahead Energy Market. Any Market Participant that elects to schedule an export, import or wheel through transaction in the Day-ahead Energy Market may specify the price (such price not to exceed $2,000/MWh), if any, at which the export, import or wheel through transaction will be wholly or partially curtailed. The foregoing price specification shall apply to the applicable interface pricing point. Any Market Participant that elects not to schedule its export, import or wheel through transaction in the Day-ahead Energy Market shall inform the Office of the Interconnection if the parties to the transaction are not willing to incur Transmission Congestion and Loss Charges in the Real-time Energy Market in order to complete any such scheduled transaction. Such transactions in the Real-time Energy Market, other than Coordinated Transaction Schedules and emergency energy sales and purchases, may specify a price up to $2,000/MWh. Scheduling of such transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

i) Market Participants shall submit schedules for all energy purchases for delivery within the PJM Region, whether from resources inside or outside the PJM Region;

ii) Market Participants shall submit schedules for exports for delivery outside the PJM Region from resources within the PJM Region that are not Dynamic Transfers to such entities pursuant to Tariff, Attachment K-Appendix, section 1.12; and

iii) In addition to the foregoing schedules for exports, imports and wheel through transactions, Market Participants shall submit confirmations of each scheduled

transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(c-1) A Market Participant may elect to submit in the Day-ahead Energy Market a form of Virtual Transaction that combines an offer to sell energy at a source, with a bid to buy the same megawatt quantity of energy at a sink where such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink. The Office of Interconnection will schedule these transactions only to the extent this difference in Locational Marginal Prices is within the maximum amount specified by the Market Participant. A Virtual Transaction of this type is referred to as an "Up-to Congestion Transaction." Such Up-to Congestion Transactions may be wholly or partially scheduled depending on the price difference between the source and sink locations in the Day-ahead Energy Market. The maximum difference between the source and sink prices that a participant may specify shall be limited to +/- $50/MWh. The foregoing price specification shall apply to the price difference between the specified source and sink in the day-ahead scheduling process only. An accepted Up-to Congestion Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-ahead Energy Market.

(c–2) A Market Participant may elect to submit an Increment Offer and/or Decrement Bid form of Virtual Transaction in the Day-ahead Energy Market and shall specify the price for such transaction which shall be limited to $2,000/megawatt-hour.

(c-3) Up-to Congestion Transactions may only be submitted at hubs, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b). Increment Offers and Decrement Bids may be only submitted at hubs, nodes at which physical generation or load is settled, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b).

(d) Market Sellers in the Day-ahead Energy Market shall submit offers for the supply of energy, demand reductions, or other services for the following Operating Day for each clock hour for which the Market Seller desires or is required to make its resource available to the Office of the Interconnection. Offers for the supply of energy may be cost-based, market-based, or both, and may vary hourly. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, Operating Agreement, Schedule 2, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that is committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. Such offers shall be based on the ICAP equivalent of the Market Seller's cleared UCAP capacity commitment, provided, however, (i) where the underlying resource is a Capacity Storage Resource, with the exception of Capacity Storage Resource participating in the Energy Storage Resource Participation Model, or an Intermittent Resource, the Market Seller shall satisfy the must offer requirement by either self-scheduling or offering the unit as a dispatchable

resource, in accordance with the PJM Manuals, where the hourly day-ahead self-scheduled values for such Capacity Storage Resources and Intermittent Resources may vary hour to hour from the capacity commitment, and (ii) where the underlying resource is a Hybrid Resource or Capacity Storage Resource participating in the Energy Storage Resource Participation Model, the Market Seller shall satisfy the must offer requirement by self-scheduling the unit in accordance with the PJM Manuals, where the hourly day-ahead self-scheduled values for such Hybrid Resource or Capacity Storage Resource may vary hour to hour from the capacity commitment. Any offer not designated as a Maximum Emergency offer shall be considered available for scheduling and dispatch under both Emergency and non-Emergency conditions. Offers may only be designated as Maximum Emergency offers to the extent that the Generation Capacity Resource falls into at least one of the following categories:

i) Environmental limits. If the resource has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited to operating only during declared PJM capacity emergencies by a governmental authority.

ii) Fuel limits. If physical events beyond the control of the resource owner result in the temporary interruption of fuel supply and there is limited on-site fuel storage. A fuel supplier's exercise of a contractual right to interrupt supply or delivery under an interruptible service agreement shall not qualify as an event beyond the control of the resource owner.

iii) Temporary emergency conditions at the unit. If temporary emergency physical conditions at the resource significantly limit its availability.

iv) Temporary megawatt additions. If a resource can provide additional megawatts on a temporary basis by oil topping, boiler over-pressure, or similar techniques, and such megawatts are not ordinarily otherwise available.

The submission of offers for resource increments that are not committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1 shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2, and the PJM Manuals, as applicable. Energy offered from generation resources that are not committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1 shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region.

The foregoing offers:

i) Shall specify the Generation Capacity Resource or Economic Load Response Participant resource and energy or demand reduction amount, respectively, for each clock hour in the offer period;

ii) Shall specify the amounts and prices for each clock hour during the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;

iii) May specify for generation resources offer parameters for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) Minimum Run Time; (2) maximum run time; (3) Start-up Costs; (4) No-load Costs; (5) Incremental Energy Offer; (6) notification time; (7) availability; (8) ramp rate; (9) Economic Minimum; (10) Economic Maximum; (11) emergency minimum MW; (12) emergency maximum MW; (13) Synchronized Reserve maximum MW; (14) Secondary Reserve maximum MW; and (15) condense to generation time constraints, and may specify offer parameters for Economic Load Response Participant resources for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) minimum down time; (2) maximum down time; (3) minimum release time; (4) shutdown costs; (5) Incremental Energy Offer; (6) notification time; (7) Economic Minimum; and (8) Economic Maximum;

iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;

v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with additional schedules applicable if accepted after the foregoing deadline;

vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer for the clock hour, which offer shall remain open through the Operating Day, for which the offer is submitted, unless the Market Seller a) submits a Real-time Offer for the applicable clock hour, or b) updates the availability of its offer for that hour, as further described in the PJM Manuals;

vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day, unless modified after the close of the Day-ahead Energy Market as permitted pursuant to sections 1.10.9A or 1.10.9B below;

viii) Shall not exceed an energy offer price of $1,000/megawatt-hour for all generation resources, except (1) when a Market Seller's cost-based offer is above $1,000/megawatt-hour and less than or equal to $2,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer; and (2) when a Market Seller's cost-based offer is greater than $2,000/megawatt-hour, then its market-based offer must be less than or equal to $2,000/megawatt-hour;

ix) Shall not exceed a demand reduction offer price of $1,000/megawatt-hour, except when an Economic Load Response Participant submits a cost-based offer that includes an incremental cost component that is above $1,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer but in no event greater than $2,000/megawatt-hour;

x) Shall not exceed an offer price as follows for Emergency Load Response and Pre-Emergency Load Response participants with:

a) a 30 minute lead time, pursuant to Tariff, Attachment DD-1, section A.2 and the parallel provision of RAA, Schedule 6, $1,000/megawatt-hour, plus the applicable Reserve Penalty Factor for the Primary Reserve Requirement, minus $1.00;

b) an approved 60 minute lead time, pursuant to Tariff, Attachment DD-1, section A.2 and the parallel provision of RAA, Schedule 6, $1,000/megawatt hour, plus [the applicable Reserve Penalty Factor for the Primary Reserve Requirement divided by 2]; and

c) an approved 120 minute lead time, pursuant to Tariff, Attachment DD-1, section A.2 and the parallel provisions of RAA, Schedule 6, $1,100/megawatt-hour; and

xi) Shall not exceed an energy offer price of $0.00/MWh for pumped storage hydropower units scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation for each 30 minute Regulation clearing interval for which the Market Seller desires to make its resource available to the Office of the Interconnection to provide Regulation that shall specify the megawatts of Regulation being offered, which must equal or exceed 0.1 megawatts, in the Regulation Zone for which such Regulation is offered, the price of the capability offer in dollars per MW, the price of the mileage offer in Dollars per change in MW, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the resource's opportunity costs. Such offers may vary for each 30 minute Regulation clearing interval, and may be updated each 30 minute Regulation clearing interval, up to 35 minutes before the applicable 30 minute Regulation clearing interval during the Operating Day. The total of the mileage offer multiplied by the historical average mileage used in the market clearing plus the capability offer shall not exceed $100/megawatt-hour. In addition to any market-based offer for Regulation, the Market Seller also shall submit a cost-based offer. A cost-based offer must be in the form specified in the PJM Manuals and consist of the following components as well as any other components specified in the PJM Manuals:

i. The costs (in $/MW) of the fuel cost increase due to the steady-state heat rate increase resulting from operating the unit at lower megawatt output incurred from the provision of Regulation shall apply to the capability offer;

ii. The cost increase (in $/ΔMW) in costs associated with movement of the regulation resource incurred from the provision of Regulation shall apply to the mileage offer; and

a. Only Regulation-only resources may include all variable operation and maintenance expenses in the mileage offer, as defined in the PJM Manuals.

iii. An adder of up to $12.00 per megawatt of Regulation provided applied to the capability offer.

Qualified Regulation capability must satisfy the measurement and verification tests specified in the PJM Manuals.

(f) Each Market Seller owning or controlling the output of a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative shall submit a forecast of the availability of each such Generation Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with Start-up Costs and No-load Costs, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours. Such resources committed by the Office of the Interconnection will not receive ~~Operating Reserve~~energy uplift Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Tariff, Attachment K-Appendix, section 3.2.3 and Tariff, Attachment K-Appendix, section 6.6.

(g) Each component of an offer by a Market Seller of a Generation Capacity Resource that is constant for the entire Operating Day and does not vary hour to hour shall remain in effect for subsequent Operating Days until superseded or canceled.

(h) The Office of the Interconnection shall post the total hourly loads scheduled in the Day-ahead Energy Market, as well as, its estimate of the combined hourly load of the Market Buyers for the next four days, and peak load forecasts for an additional three days.

(i) Except for Economic Load Response Participants, all Market Participants may submit Virtual Transactions that apply to the Day-ahead Energy Market only. Such Virtual Transactions must comply with the requirements set forth in the PJM Manuals and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-ahead Energy Market. The Office of the Interconnection may require that a market participant shall not submit in excess of a defined number of bid/offer segments in the

Day-ahead Energy Market, as specified in the PJM Manuals, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to 10:00 a.m. EPT on the day that the Day-ahead Energy Market will clear. For purposes of this provision, a bid/offer segment is each pairing of price and megawatt quantity submitted as part of an Increment Offer or Decrement Bid. For purposes of applying this provision to an Up-to Congestion Transaction, a bid/offer segment shall refer to the pairing of a source and sink designation, as well as price and megawatt quantity, that comprise each Up-to Congestion Transaction.

(j) (i) Offers to Supply Synchronized and Non-Synchronized Reserves By Generation Resources in the Day-ahead and Real-time Reserve Markets

(1) Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Tariff, Attachment DD, is capable of providing Synchronized Reserve or Non-Synchronized Reserve as specified in section 1.7.19A(a), in section 1.7.19A.01(a) and in the PJM Manuals, and has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage, shall submit offers or otherwise make their 10-minute reserve capability available to supply Synchronized Reserve or, as applicable, Non-Synchronized Reserve, including any portion that is self-scheduled by the Generating Market Buyer, in an amount equal to the available 10-minute reserve capability of such Generation Capacity Resource. Market Sellers of Generation Capacity Resources subject to this must-offer requirement that do not make the reserve capability of such resources available when such resource is able to operate with a dispatchable range (e.g. through offering a fixed output) will be in violation of this provision.

(2) Market Sellers of all other generation resources that (A) are capable of providing Synchronized Reserve or Non-Synchronized Reserve, as specified in section 1.7.19A(a), in section 1.7.19A.01(a) and in the PJM Manuals, (B) are located within the metered boundaries of the PJM Region, and (C) have submitted offers for the supply of energy into the Day-ahead Energy Market and/or Real-time Energy Market shall be deemed to have made their reserve capability available to provide Synchronized Reserve or Non-Synchronized Reserve in the Day-ahead Energy Market and/or Real-time Energy Market for each clock hour for which the Market Seller submits an available offer to supply energy; provided, however that hydroelectric generation resources and Energy Storage Resources are not automatically deemed available to provide reserves based on the submission of an available energy offer but may submit offers to supply Synchronized Reserve and Non-Synchronized Reserve, as applicable.

(3) Offers for the supply of Synchronized Reserve by all generation resources must be cost-based. Consistent with the resource's offer to supply

energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A, section 1.10.9B below, and the PJM Manuals, as applicable. For offers to supply Synchronized Reserve, the offer price shall not exceed the expected value of the penalty for failing to provide Synchronized Reserve, where such expected value shall be recalculated annually, in accordance with the PJM Manuals, and posted on PJM's website. The expected value of the penalty is calculated as the product of: (A) the average penalty, expressed in $/MWh, multiplied by (B) the average rate of non-performance during Synchronized Reserve events multiplied by (C) the probability a Synchronized Reserve event that will qualify for non-performance assessments will occur.

The expected value of the penalty shall be determined by an annual review of the twelve-month period ending October 31 of the calendar year in which the review is performed. The Office of the Interconnection shall post the results of its annual review by no later than December 15, and the revised offer price cap shall be effective as of the following January 1; provided, however, that at the time of implementation of this rule the expected value of the penalty shall be $0.02/MWh, and for the period from the second month after implementation through the second December 31 following such date of implementation, the expected value of the penalty shall be recalculated on a monthly basis using data from the implementation date of this rule through the 15th day of the current month, and the revised value shall be effective the 1st day of the following month.

(4) All Non-Synchronized Reserve offers shall be for $0.00/MWh. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this subsection (d) of this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

(ii) Determination of Available Synchronized Reserve Capability of Generation Resources

(1) For each offer to supply reserves by a synchronized resource, the Office of the Interconnection shall determine the MW of available Synchronized Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market, in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Hydroelectric generation resources and Energy Storage Resources may submit offers for their available Synchronized

Reserve capability as part of their offer into the Synchronized Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(j)(i) above must submit a Synchronized Reserve offer which specifies the MW of available Synchronized Reserve capability in order to remain compliant with such requirements.

(2) An on-line generation resource's available Synchronized Reserve capability, except for generation resources capable of synchronous condensing, shall be determined in accordance with the PJM Manuals and based on the resource's current performance and initial energy output and the following offer parameters submitted as part of the resource's energy offer: (A) ramp rate; (B) Economic Minimum; and (C) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Synchronized Reserves above the Synchronized Reserve maximum MW.

For generation resources capable of synchronous condensing, the resource's available Synchronized Reserve capability shall be based on the following offer parameters submitted as part of the resource's energy offer: (D) ramp rate; (E) condense to generation time constraints; (F) Economic Minimum; and (G) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Synchronized Reserves above the Synchronized Reserve maximum MW.

(3) Any Market Seller that believes its generating unit has operating modes, limits, or conditions where the unit would not be capable of providing Synchronized Reserves in real time, can submit to the Office of the Interconnection with a copy to the Market Monitoring Unit a request for an exception from being assigned Synchronized Reserves in the Real-time Synchronized Reserve Market during time periods in which the generating unit is in those operating modes, limits, or conditions. As part of the request, the Market Seller shall supply, for each generating unit, technical information about the operational modes, limits, or conditions to support the requested exception, as further detailed in the PJM Manuals. The Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a request for such an exception. Within 60 days of the submission of the request, the Office of the Interconnection shall notify the Market Seller in writing, with a copy to the

Market Monitoring Unit, whether the request is approved or denied. The effective date of any approved request will be provided in the written notification. If a Market Seller has an approved exception, the Market Seller must communicate to the Office of the Interconnection when the unit cannot provides reserves, and the Office of the Interconnection will provide a mechanism for Market Sellers with an approved exception to provide such communication to the Office of the Interconnection in real time, as further detailed in the PJM Manuals. An approved exception will remain applicable to the unit until such time as the Office of the Interconnection determines that a change is needed or the Market Seller notifies the Office of the Interconnection, with a copy to the Market Monitoring Unit, that a change is needed based on changed operational capabilities of the unit. Market Sellers must notify the Office of the Interconnection, with a copy to the Market Monitoring Unit, within 30 days of any changed operational capabilities that necessitate a change in an approved exception.

(iii) Determination of Available Non-Synchronized Reserve Capability of Generation Resources

(1) For each offer to supply reserves by an off-line generation resource, the Office of the Interconnection shall determine the MW of available Non-Synchronized Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Such hydroelectric generation resources or Energy Storage Resources may submit offers for their available Non-Synchronized Reserve capability as part of their offer into the Non-Synchronized Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(j)(i) above must submit a Non-Synchronized Reserve offer which specifies the MW of available Non-Synchronized Reserve capability in order to remain compliant with such requirements.

(2) An off-line generation resource's available Non-Synchronized Reserve capability shall be determined in accordance with the PJM Manuals and based on the following offer parameters submitted as part of the resource's energy offer: (A) startup time; (B) notification time; (C) ramp rate; (D) Economic Minimum; and (E) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Non-Synchronized Reserves above its Synchronized Reserve maximum MW.

(iv) Offers to Supply Synchronized Reserves by Economic Load Response Participant Resources in the Day-ahead and Real-time Reserve Markets

(1) Economic Load Response Participants that submit offers to reduce demand into the Day-ahead Energy Market and Real-time Energy Market and wish to make their resources available to supply Synchronized Reserve may submit offers to supply Synchronized Reserve from such resources, where such offers shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.1 megawatts and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day.

(2) All offers to supply Synchronized Reserve offers from Economic Load Response Participant resources shall not exceed the expected value of the penalty for failing to provide Synchronized Reserve, as determined in accordance with section 1.10.1A(j)(i)(3) above. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

(k) An Economic Load Response Participant that wishes to participate in the Day-ahead Energy Market by reducing demand shall submit an offer to reduce demand to the Office of the Interconnection for each clock hour for which the Economic Load Response Participant desires to make its resource available to the Office of the Interconnection to reduce demand. The offer must equal or exceed 0.1 megawatts, may vary hourly, and shall specify: (i) the amount of the offered curtailment in minimum increments of .1 megawatts: (ii) the Day-ahead Locational Marginal Price above which the end-use customer will reduce load, subject to section 1.10.1A(d)(ix); and (iii) at the Economic Load Response Participant's option, shutdown costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum of number of contiguous hours for which the load reduction must be committed. Such offers may be updated each hour, up to 65 minutes before the applicable clock hour during the Operating Day. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs) per hour.

(l) Market Sellers owning or controlling the output of an Economic Load Response Participant resource that was committed in an FRR Capacity Plan, or that was self-supplied or that offered and cleared in a Base Residual Auction or Incremental Auction, may submit demand reduction bids for the available load reduction capability of the Economic Load Response Participant resource. The submission of demand reduction bids for Economic Load Response Participant resource increments that were not committed in an FRR Capacity Plan, or that have not cleared in a Base Residual Auction or Incremental Auction, shall be optional, but any such bids must contain the information required to be included in such bids, as specified in the PJM Economic Load Response Program. An Economic Load Response Participant resource that was committed in an FRR Capacity Plan, or that was self-supplied or offered and cleared in a Base

Residual Auction or Incremental Auction, may submit a demand reduction bid in the Day-ahead Energy Market as specified in the Economic Load Response Program; provided, however, that in the event of an Emergency PJM shall require Economic Load Response Participant resources to reduce load, notwithstanding that the Zonal LMP at the time such Emergency is declared is below the price identified in the demand reduction bid.

(m) (i) Offers to Supply Secondary Reserve By Generation Resources

(1) Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Tariff, Attachment DD, that is available for energy, is capable of providing Secondary Reserve, as specified in section 1.7.19A.02(a) and in the PJM Manuals, and has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers to supply Secondary Reserve, or otherwise make their Secondary Reserve capability available. Such offers shall be for an amount equal to the resource's available energy output achievable within thirty minutes (less its energy output achievable within ten minutes) from a request of the Office of the Interconnection. Market Sellers of Generation Capacity Resources subject to this must-offer requirement that do not make the reserve capability of such resources available when such resource is able to operate with a dispatchable range (e.g. through offering a fixed output) will be in violation of this provision.

(2) Market Sellers of all other generation resources located within the metered boundaries of the PJM Region that submit offers for the supply of energy into the Day-ahead Energy Market and/or Real-time Energy Market and are capable of providing Secondary Reserve, as specified in the PJM Manuals, shall be deemed to have made their reserve capability available to provide Secondary Reserve in the Day-ahead Energy Market and/or Real-time Energy Market for each clock hour for which the Market Seller submits an available offer to supply energy; provided, however that hydroelectric generation resources and Energy Storage Resources are not automatically deemed available to provide reserves based on the submission of an available energy offer but may submit offers to supply Secondary Reserve, as applicable.

(3) Offers for the supply of Secondary Reserve shall be for $0.00/MWh. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this subsection (d) above, section 1.10.9B below, and the PJM Manuals, as applicable.

(ii) Determination of Available Secondary Reserve Capability of Generation Resources

(1) For each offer to supply Secondary Reserve by a generation resource, the Office of the Interconnection shall determine the MW of available Secondary Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Hydroelectric generation resources or Energy Storage Resources may submit their available Secondary Reserve capability as part of their offer into the Secondary Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(m)(i) above must submit a Secondary Reserve offer which specifies the MW of available Secondary Reserve capability in order to remain compliant with such requirements.

(2) (A) An on-line generation resource's available Secondary Reserve capability, except for generation resources capable of synchronous condensing, shall be based on the resource's current performance and initial energy output, the resource's available Synchronized Reserve capability; and the following offer parameters submitted as part of the energy offer: (i) ramp rate; (ii) Economic Minimum; and (iii) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(B) For generation resources capable of synchronous condensing, the resource's available Secondary Reserve capability shall be based on the following offer parameters submitted as part of the energy offer: (i) ramp rate; (ii) condense to generation time constraints; (iii) Economic Minimum; and (iv) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(C) An off-line generation resource's available Secondary Reserve capability, shall be based on the resource's available Secondary

Reserve capability and the following offer parameters submitted as part of the resource's energy offer: (i) startup time; (ii) notification time; (iii) ramp rate; (iv) Economic Minimum; and (v) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(3) Any Market Seller that believes its generating unit has operating modes, limits, or conditions where the unit would not be capable of providing Secondary Reserves in real time, can submit to the Office of the Interconnection with a copy to the Market Monitoring Unit a request for an exception from being assigned Secondary Reserves in the Real-time Secondary Reserve Market during time periods in which the generating unit is in those operating modes, limits, or conditions. As part of the request, the Market Seller shall supply, for each generating unit, technical information about the operational modes, limits, or conditions to support the requested exception, as further detailed in the PJM Manuals. The Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a request for such an exception. Within 60 days of the submission of the request, the Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, whether the request is approved or denied. The effective date of any approved request will be provided in the written notification. If a Market Seller has an approved exception, the Market Seller must communicate to the Office of the Interconnection when the unit cannot provides reserves, and the Office of the Interconnection will provide a mechanism for Market Sellers with an approved exception to provide such communication to the Office of the Interconnection in real time, as further detailed in the PJM Manuals. An approved exception will remain applicable to the unit until such time as the Office of the Interconnection determines that a change is needed or the Market Seller notifies the Office of the Interconnection, with a copy to the Market Monitoring Unit, that a change is needed based on changed operational capabilities of the unit. Market Sellers must notify the Office of the Interconnection, with a copy to the Market Monitoring Unit, within 30 days of any changed operational capabilities that necessitate a change in an approved exception.

(iii) Offers to Supply Secondary Reserves by Economic Load Response Participant resources

(1) Each Economic Load Response Participant that submits offers to reduce demand into the Day-ahead Energy Market and Real-time Energy Market and wishes to make their resources available to supply Secondary Reserve shall submit offers to supply Secondary Reserve from such resources, where such offers shall specify the megawatts of Secondary Reserve being offered, which must equal or exceed 0.1 megawatts and include such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day.

(2) All Secondary Reserve offers by Economic Load Response Participant resources shall be for $0.00/MWh. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

(n) A Market Participant may submit a Day-Ahead Pseudo-Tie Transaction for a Market Participant's generator within the PJM balancing authority area that is a Pseudo-Tie into the MISO balancing authority area. Day-Ahead Pseudo-Tie Transactions combine an offer to sell energy at a source with a bid to buy the same megawatt quantity of energy at a sink where such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink.

Each Day-Ahead Pseudo-Tie Transaction shall: (1) source at a Market Participant's generator within the PJM balancing authority area that Pseudo-Ties into MISO; and (2) sink at the PJM-MISO interface. A Market Participant must reserve transmission service in accordance with the PJM Tariff for each Day-Ahead Pseudo-Tie Transaction. Megawatt quantities for Day-Ahead Pseudo-Tie Transactions shall be greater than zero and less than or equal to the transmission service reserved for the Day-Ahead Pseudo-Tie Transaction. An accepted Day-Ahead Pseudo-Tie Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-Ahead Energy Market.

1.10.1B Demand Bid Scheduling and Screening

(a) The Office of the Interconnection shall apply Demand Bid Screening to all Demand Bids submitted in the Day-ahead Energy Market for each Load Serving Entity, separately by Zone. Using Demand Bid Screening, the Office of the Interconnection will automatically reject a Load Serving Entity's Demand Bids in any future Operating Day for which the Load Serving Entity submits bids if the total megawatt volume of such bids would exceed the Load Serving Entity's Demand Bid Limit for any hour in such Operating Day, unless the Office of the Interconnection permits an exception pursuant to subsection (d) below.

(b) On a daily basis, PJM will update and post each Load Serving Entity's Demand Bid Limit in each applicable Zone. Such Demand Bid Limit will apply to all Demand Bids submitted by that Load Serving Entity for each future Operating Day for which it submits bids. The Demand Bid Limit is calculated using the following equation:

Demand Bid Limit = greater of (Zonal Peak Demand Reference Point * 1.3), or (Zonal Peak Demand Reference Point + 10MW)

Where:

1. Zonal Peak Demand Reference Point = for each Zone: the product of (a) LSE Recent Load Share, multiplied by (b) Peak Daily Load Forecast.
2. LSE Recent Load Share is the Load Serving Entity's highest share of Network Load in each Zone for any hour over the most recently available seven Operating Days for which PJM has data.
3. Peak Daily Load Forecast is PJM's highest available peak load forecast for each applicable Zone that is calculated on a daily basis.

(c) A Load Serving Entity whose Demand Bids are rejected as a result of Demand Bid Screening may change its Demand Bids to reduce its total megawatt volume to a level that does not exceed its Demand Bid Limit, and may resubmit them subject to the applicable rules related to bid submission outlined in Tariff, Operating Agreement and PJM Manuals.

(d) PJM may allow a Load Serving Entity to submit bids in excess of its Demand Bid Limit when circumstances exist that will cause, or are reasonably expected to cause, a Load Serving Entity's actual load to exceed its Demand Bid Limit on a given Operating Day. Examples of such circumstances include, but are not limited to, changes in load commitments due to state sponsored auctions, mergers and acquisitions between PJM Members, and sales and divestitures between PJM Members. A Load Serving Entity may submit a written exception request to the Office of Interconnection for a higher Demand Bid Limit for an affected Operating Day. Such request must include a detailed explanation of the circumstances at issue and supporting documentation that justify the Load Serving Entity's expectation that its actual load will exceed its Demand Bid Limit.

1.10.2 Pool-scheduled Resources.

Pool-scheduled resources are those resources for which Market Participants submitted offers to sell energy in the Day-ahead Energy Market and offers to reduce demand in the Day-ahead Energy Market, which the Office of the Interconnection scheduled in the Day-ahead Energy Market as well as generators committed by the Office of the Interconnection subsequent to the Day-ahead Energy Market. Such resources shall be committed to provide energy in the real-time dispatch unless the schedules for such units are revised pursuant to section 1.10.9 below or Tariff, Attachment K-Appendix, section 1.11. Pool-scheduled resources shall be governed by the following principles and procedures.

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, whether the resource is expected to be needed to maintain system reliability during the Operating Day, Start-up Costs, No-load Costs and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in section 1.10.1A above. Hydropower units can only be pool-scheduled if they are pumped

storage units and scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

(b) A resource that is scheduled by a Market Participant to support a bilateral sale, or that is self-scheduled by a Generating Market Buyer, shall not be selected by the Office of the Interconnection as a pool-scheduled resource except in an Emergency.

(c) Market Sellers offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the Office of the Interconnection that is sufficient to enable the Office of the Interconnection to determine the available operating hours of such facilities.

(d) The Market Seller of a resource selected as a pool-scheduled resource shall receive payments or credits for energy, demand reductions or related services, or for Start-up Costs and No-load Costs, from the Office of the Interconnection on behalf of the Market Buyers in accordance with Tariff, Attachment K-Appendix, section 3. Alternatively, the Market Seller shall receive, in lieu of Start-up Costs and No-load Costs, its actual costs incurred, if any, up to a cap of the resource's Start-up Costs, if the Office of the Interconnection cancels its selection of the resource as a pool-scheduled resource and so notifies the Market Seller before the resource is synchronized.

(e) Market Participants shall make available their pool-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone.

(f) Economic Load Response Participants offering to reduce demand shall specify: (i) the amount of the offered curtailment, which must equal or exceed 0.1 megawatts, in minimum increments of 0.1 megawatts; (ii) the real-time Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, shut-down costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum number of contiguous hours for which the load reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market and/or the Real-time Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs). Economic Load Response Participants offering to reduce demand shall also indicate the hours that the demand reduction is not available.

1.10.3 Self-scheduled Resources.

Self-scheduled resources shall be governed by the following principles and procedures.

(a) Each Generating Market Buyer shall use all reasonable efforts, consistent with Good Utility Practice, not to self-schedule resources in excess of its Equivalent Load.

(b) The offered prices of resources that are self-scheduled and not dispatchable by the Office of the Interconnection shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.

(c) Market Participants shall make available their self-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone, by submitting an offer as to such resources.

(d) A Market Participant self-scheduling a resource in the Day-ahead Energy Market that does not deliver the energy in the Real-time Energy Market, shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(e) A Market Participant self-scheduling a resource to supply Synchronized Reserve in the Day-ahead Synchronized Reserve Market that does not deliver the scheduled megawatt quantity in the applicable real-time reserve market, shall replace the Synchronized Reserve not delivered and shall pay for such Synchronized Reserve at the applicable Real-time Synchronized Reserve Market Clearing Price. Market Participants shall not self-schedule a resource to provide Secondary Reserve or Non-Synchronized Reserve.

(f) For energy, hydropower units, excluding pumped storage units, may only be self-scheduled.

(g) A resource that has been self-scheduled shall not receive payments or credits for Start-up Costs or No-load Costs.

1.10.4 Capacity Resources.

(a) A Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that is selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection. Such a Generation Capacity Resource that does not deliver energy as scheduled shall be deemed to have experienced a Generator Forced Outage to the extent of such energy not delivered. A Market Participant offering such Generation Capacity Resource in the Day-ahead Energy Market shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Energy from a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that has not been scheduled in the Day-ahead Energy Market may be sold on a bilateral basis by the Market Seller, may be self-scheduled, or may be offered for dispatch during the Operating Day in accordance with the procedures specified in this Schedule. Such a Generation Capacity Resource that has not been scheduled in the Day-ahead Energy Market and that has been sold on a bilateral basis must be made available upon request to the Office of the Interconnection for scheduling and dispatch during the Operating Day if the Office of the Interconnection declares a Maximum

Generation Emergency. Any such resource so scheduled and dispatched shall receive the applicable Real-time Price for energy delivered.

1.10.5 External Resources.

(a) External Resources may submit offers to the PJM Interchange Energy Market, in accordance with the day-ahead and real-time scheduling processes specified above. An External Resource selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection, and except as specified below shall be compensated on the same basis as other pool-scheduled resources. External Resources that are not capable of Dynamic Transfer shall, if selected by the Office of the Interconnection on the basis of the Market Seller's Offer Data, be block loaded on an hourly scheduled basis. Market Sellers shall offer External Resources to the PJM Interchange Energy Market on either a resource-specific or an aggregated resource basis. A Market Participant whose pool-scheduled resource does not deliver the energy scheduled in the Day-ahead Energy Market shall replace such energy not delivered as scheduled in the Day-ahead Energy Market with energy from the PJM Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Offers for External Resources from an aggregation of two or more generating units shall so indicate, and shall specify, in accordance with the Offer Data requirements specified by the Office of the Interconnection: (i) energy prices; (ii) hours of energy availability; (iii) a minimum dispatch level; (iv) a maximum dispatch level; and (v) unless such information has previously been made available to the Office of the Interconnection, sufficient information, as specified in the PJM Manuals, to enable the Office of the Interconnection to model the flow into the PJM Region of any energy from the External Resources scheduled in accordance with the Offer Data.

(c) Offers for External Resources on a resource-specific basis shall specify the resource being offered, along with the information specified in the Offer Data as applicable.

1.10.6 External Market Buyers.

(a) Deliveries to an External Market Buyer not subject to Dynamic Transfer by the Office of the Interconnection shall be delivered on a block loaded basis to the bus or buses at the electrical boundaries of the PJM Region, or in such area with respect to an External Market Buyer's load within such area not served by Network Service, at which the energy is delivered to or for the External Market Buyer. External Market Buyers shall be charged (which charge may be positive or negative) at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing bus or buses.

(b) An External Market Buyer's hourly schedules for energy purchased from the PJM Interchange Energy Market shall conform to the ramping and other applicable requirements of the interconnection agreement between the PJM Region and the Control Area to which, whether as an intermediate or final point of delivery, the purchased energy will initially be delivered.

(c) The Office of the Interconnection shall curtail deliveries to an External Market Buyer if necessary to maintain appropriate reserve levels for a Control Zone as defined in the PJM Manuals, or to avoid shedding load in such Control Zone.

1.10.7 Bilateral Transactions.

Bilateral transactions as to which the parties have notified the Office of the Interconnection by the deadline specified in section 1.10.1A above that they elect not to be included in the Day-ahead Energy Market and that they are not willing to incur Transmission Congestion Charges in the Real-time Energy Market shall be curtailed by the Office of the Interconnection as necessary to reduce or alleviate transmission congestion. Bilateral transactions that were not included in the Day-ahead Energy Market and that are willing to incur congestion charges and bilateral transactions that were accepted in the Day-ahead Energy Market shall continue to be implemented during periods of congestion, except as may be necessary to respond to Emergencies.

1.10.8 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers and PRD Curves properly submitted by PRD Providers; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv) the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated flowgates to the extent provided by Tariff, Attachment K-Appendix, section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) By 1:30 p.m., or as soon as practicable thereafter, of the day before each Operating Day, or such other deadline as may be specified by the Office of the Interconnection in the PJM Manuals, the Office of the Interconnection shall: (i) post the aggregate Day-ahead

Energy Market results; (ii) post the Day-ahead Prices; and (iii) inform the Market Sellers, Market Buyers, and Economic Load Response Participants of their scheduled injections, withdrawals, and demand reductions respectively. The foregoing notwithstanding, the deadlines set forth in this subsection shall not apply if the Office of the Interconnection is unable to obtain Market Participant bid/offer data due to extraordinary circumstances. For purposes of this subsection, extraordinary circumstances shall mean a technical malfunction that limits, prohibits or otherwise interferes with the ability of the Office of the Interconnection to obtain Market Participant bid/offer data prior to 11:59 p.m. on the day before the affected Operating Day. Extraordinary circumstances do not include a Market Participant's inability to submit bid/offer data to the Office of the Interconnection. If the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day as a result of such extraordinary circumstances, the Office of the Interconnection shall notify Members as soon as practicable.

(c) Following posting of the information specified in section 1.10.8(b), and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, the Office of the Interconnection shall revise its schedule of generation resources to reflect updated projections of load, conditions affecting electric system operations in the PJM Region, the availability of and constraints on limited energy and other resources, transmission constraints, and other relevant factors.

(d) Market Buyers shall pay PJMSettlement and Market Sellers shall be paid by PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is positive. Market Buyers shall be paid by PJMSettlement and Market Sellers shall pay PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Tariff, Attachment K-Appendix, section 3.3A. Notwithstanding the foregoing, if the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day due to extraordinary circumstances as described in subsection (b) above, it will be declared a Market Suspension, and Day-ahead Prices shall be determined pursuant to Operating Agreement, Schedule 1, section 2.6.1. If the Office of the Interconnection declares a Market Suspension, it shall notify Market Participants of the Market Suspension as soon as practicable.

(e) If the Office of the Interconnection discovers a *potential* error in prices and/or cleared quantities in the Day-ahead Energy Market or Day-ahead Ancillary Services Markets, or the Real-time Energy Market or Real-time Ancillary Services Markets after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants as soon as possible after it is found, but in no event later than 12:00 p.m. of the second Business Day following the Operating Day for the Real-time Energy Market and Real-time Ancillary Services Markets, and no later than 5:00 p.m. of the second Business Day following the initial publication of the results for the Day-ahead Energy Market and Day-ahead Ancillary Services Markets. After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, *along with a description detailing the cause and scope of the error*, by no later than 5:00 p.m.

of the fifth Business Day following the Operating Day for the Real-time Energy Market and Real-time Ancillary Services Markets, and no later than 5:00 p.m. of the fifth Business Day following the initial publication of the results in the Day-ahead Energy Market and Day-ahead Ancillary Services Markets. *The provided description will not contain information that is market sensitive or confidential.* Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating Day for the Day-ahead Energy Market, Real-time Energy Market, and Day-ahead Ancillary Services Markets, and Real-time Ancillary Service Markets. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced market results are under publicly noticed review by the FERC.

(f) Consistent with Operating Agreement, section 18.17.1, and notwithstanding anything to the contrary in the Operating Agreement or in the PJM Tariff, to allow the tracking of Market Participants' non-aggregated bids and offers over time as required by FERC Order No. 719, the Office of the Interconnection shall post on its Web site the non-aggregated bid data and Offer Data submitted by Market Participants (for participation in the PJM Interchange Energy Market) approximately four months after the bid or offer was submitted to the Office of the Interconnection.

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, a generation rebidding period shall exist. Typically the rebidding period shall be from the time the Office of the Interconnection posts the results of the Day-ahead Energy Market until 2:15 p.m. on the day before each Operating Day. However, should the clearing of the Day-ahead Energy Market be significantly delayed, the Office of the Interconnection may establish a revised rebidding period. During the rebidding period, Market Participants may submit revisions to generation Offer Data for the next Operating Day. Adjustments to the Day-ahead Energy Market shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 6:30 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 65 minutes prior to the hour in which the adjustment is to take effect, as follows and as specified in section 1.10.9A below:

i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;

ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or

iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or

iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any Start-Up Costs.

(c) An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase in the Day-ahead Energy Market by notifying the Office of the Interconnection of the adjustment in deliveries not later than 65 minutes prior to the hour in which the adjustment is to take effect, but any such adjustment shall not affect the obligation of the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(d) The Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules resulting from the rebidding period by 6:30 p.m. on the day before each Operating Day. The Office of the Interconnection may also commit additional resources after such time as system conditions require. For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this section 1.10, the Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules for the hour.

1.10.9A Updating Offers in Real-time

(a) Each Market Seller may submit Real-time Offers for a resource up to 65 minutes before the applicable clock hour, and such Real-time Offers shall supersede any previous offer for that resource for the clock hour, as further described in the PJM Manuals and subject to the following conditions:

(i) A market-based Real-time Offer shall not exceed the applicable energy offer caps specified in this Schedule. Once a Market Seller's resource is committed for an applicable clock hour, the Market Seller may not increase its Incremental Energy Offer and may only submit a market-based Real-time Offer that is higher than its market-based offer that was in effect at the time of commitment to reflect increases in the resource's cost-based Start-up Costs and cost-based No-load Costs. The Market Seller may elect not to have its market-based offer considered for dispatch and to have only its lowest cost-based offer considered for the remainder of the Operating Day.

(ii) Cost-based Real-time Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2 and the PJM Manuals, as applicable. If a Market Seller submits a market-based Real-time Offer for a particular clock hour in accordance with subsection (c) below, or if updates to a cost-based offer are required by the Market Seller's approved Fuel Cost Policy, the Market Seller shall update its previously submitted cost-based Real-time Offer.

(iii) If a Market Seller's available cost-based offer is not compliant with Operating Agreement, Schedule 2 and the PJM Manuals at the time a Market Seller submits a market-based Real-time Offer for an applicable clock hour during the Operating Day, the Market Seller must submit an updated cost-based Real-time Offer consisting of an Incremental Energy Offer, Start-up Cost and No-load Cost for that clock hour that is compliant with Operating Agreement, Schedule 2 and the PJM Manuals.

(b) Each Market Seller may submit Real-time Offers for a resource during and through the end of the applicable clock hour to update only the following offer parameters, as further described in the PJM Manuals: (1) Economic Minimum; (2) Economic Maximum; (3) emergency minimum MW; (4) emergency maximum MW; (5) unit availability status; (6) fixed output indicator; (7) Synchronized Reserve maximum MW; and (8) Secondary Reserve maximum MW. Such Real-time Offers shall supersede any previous offer for that resource for the clock hour.

1.10.9B Offer Parameter Flexibility

(a) Market Sellers may, in accordance with sections 1.10.1A and 1.10.9A above, this section 1.10.9B, and the PJM Manuals, update offer parameters at any time up to 65 minutes before the applicable clock hour, including prior to the close of the Day-ahead Energy Market and prior to the close of the rebidding period specified in section 1.10.9, except that Market Sellers may not update their offers for the supply of energy, Secondary Reserve, Synchronized Reserve, Non-Synchronized Reserve, or demand reduction: (1) during the period after the close the Day-ahead Energy Market and prior to the posting of the Day-ahead Energy Market results pursuant to section 1.10.8(b); or (2) during the period after close of the rebidding period and prior to PJM announcing the results of the rebidding period pursuant to section 1.10.9(d).

(b) For generation resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) cost-based Start-up Costs; (2) cost-based No-load Costs; (3) Incremental Energy Offer; (4) Economic Minimum and Economic Maximum; (5) emergency minimum MW and emergency maximum MW; (6) ramp rate; (7) Synchronized Reserve maximum MW; (8) Secondary Reserve maximum MW; and (9) for Real-time Offers only, (i) notification time and (ii) for uncommitted hours only, Minimum Run Time. Notwithstanding the foregoing, Market Sellers of generation resources may vary the notification time for each clock hour for purposes of committing Non-Synchronized Reserve and offline Secondary Reserve in both the Day-ahead and Real-time reserve commitments.

(c) For Economic Load Response Participant resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) shutdown costs, (2) Incremental Energy Offer; (3) Economic Minimum; (4) Economic

Maximum; and (5) for Real-time Offers only, (i) notification time and (ii) for uncommitted hours only, minimum down time.

(d) After the announcement of the results of the rebidding period pursuant to section 1.10.9(d), a Market Seller may submit a Real-time Offer where offer parameters may differ from the offer originally submitted in the Day-ahead Energy Market, except that a Market Seller may not submit a Real-time Offer that changes, of the offer parameters listed in section 1.10.1A(d), the MW amounts specified in the Incremental Energy Offer, MW amounts specified in the ramp rate, maximum run time, and availability; provided, however, Market Sellers of dual-fueled resources may submit Real-time Offers for such resources that change the availability of a submitted cost-based offer.

1.12 Dynamic Transfers.

(a) An entity that owns or controls a generating resource in the PJM Region may request that the Transmission Provider electrically remove all or part of the generating resource's output from the PJM Region through a Dynamic Transfer of the output to load outside the PJM Region. Such output shall not be available for economic dispatch by the Office of the Interconnection. A Market Participant otherwise eligible pursuant to section 3.2.3 to submit start-up and no-load values of a generating unit for consideration in calculation of the Energy Make Whole credit~~Operating Reserve Credit~~ shall not be so eligible if all of the output of the generating unit is transferred outside of the PJM Region by a Dynamic Transfer.

(b) An entity that owns or controls a generating resource outside of the PJM Region may request that the Transmission Provider electrically add all or part of the generating resource's output to the PJM Region through a Dynamic Transfer of the output to load inside the PJM Region. A Market Participant otherwise eligible pursuant to section 3.2.3 to submit start-up and no-load values of a generating unit for consideration in calculation of the Energy Make Whole credit~~Operating Reserve Credit~~ shall be so eligible only if all of the output of the generating unit is transferred into the PJM Region by a Dynamic Transfer.

(c) The Transmission Provider may implement Dynamic Transfers pursuant to a request under subsections (a) or (b) above, provided that the requesting entity can demonstrate to the satisfaction of the Transmission Provider that the requesting entity has arranged for the provision of signal processing and communications from the generating unit to the Office of the Interconnection and other participating control areas and remains in compliance with any other procedures and operational requirements established by the Office of the Interconnection regarding Dynamic Transfer as set forth in the PJM Manuals.

(d) An entity requesting a Dynamic Transfer shall be responsible for reserving the amount of transmission service necessary to deliver the range of the Dynamic Transfer and any required ancillary services as applicable. Firm or non-firm transmission service may be used to deliver Dynamic Schedules. Dynamic Schedules are not eligible to provide ancillary services. Only firm transmission service may be used to deliver Pseudo-Ties. Pseudo-Ties are eligible to provide Regulation, Synchronized Reserve and Non-Synchronized Reserve as further described in the PJM Manuals. An entity seeking to utilize a Dynamic Schedule to coordinate operations and beneficially manage congestion in real time with PJM may execute a mutually agreeable interregional congestion management agreement as contemplated in Section 2.6A of this Schedule. An entity seeking to utilize a Pseudo-Tie shall execute a mutually agreeable interregional congestion management agreement as contemplated in Section 2.6A of this Schedule. An entity seeking to utilize a Dynamic Transfer shall execute an agreement prescribing the requirements that must be met before PJM will implement the requested Dynamic Transfer. Dynamic Schedule transactions that occur in real time pursuant to such a congestion management agreement may utilize after-the-fact transmission reservations to account for actual energy transfers.

(e) The Market Participant shall cooperate with PJM to ensure that changes in the Dynamic Transfer value do not adversely impact PJM's management of the PJM Area Control

Error in a manner unacceptable to PJM, and, in the event that PJM, in its sole discretion, determines that the Market Participant's actions in this regard are unacceptable, PJM may terminate the Dynamic Transfer arrangement and may require such additional conditions as it deems appropriate prior to any further Dynamic Transfers.

(f) Market Sellers of generators and other sources otherwise eligible pursuant to Schedule 2 of the PJM Tariff to receive compensation for providing reactive supply and voltage control shall not be so eligible if the generating unit is outside of the PJM Region regardless of whether the generating unit is transferred into the PJM Region by a Dynamic Transfer.

3.2 Market Settlements.

If a dollar-per-MW-hour value is applied in a calculation under this section 3.2 where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW hour value is divided by the number of Real-time Settlement Intervals in the hour.

3.2.1 Spot Market Energy.

(a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with Tariff, Attachment K-Appendix, section 2.

(b) Each Market Participant shall be charged for all of its Market Participant Energy Withdrawals scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price to be served in the PJM Interchange Energy Market.

(c) Each Market Participant shall be paid for all of its Market Participant Energy Injections scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price to be delivered to the PJM Interchange Energy Market.

(d) For each Day-ahead Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its Market Participant Energy Withdrawals scheduled times the Day-ahead System Energy Price and the sum of its Market Participant Energy Injections scheduled times the Day-ahead System Energy Price.

(e) For each Real-time Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its real-time Market Participant Energy Withdrawals less its scheduled Market Participant Energy Withdrawals times the Real-time System Energy Price and the sum of its real-time Market Participant Energy Injections less scheduled Market Participant Energy Injections times the Real-time System Energy Price. The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Tariff, Attachment K-Appendix, section 3.1A shall be used in determining the real-time Market Participant Energy Withdrawals and Market Participant Energy Injections used to calculate Spot Market Energy charges under this subsection (e).

(f) For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the megawatts of real-time energy injections to be delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region

3.2.2 Regulation.

(a) Each Market Participant that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation Requirement of such Regulation Zone for the hour, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). A Market Participant with an hourly Regulation Obligation shall be charged the pro rata share of the sum of the Regulation market mileage clearing price credits and Regulation market capability clearing price credits for the Real-time Settlement Intervals in an hour.

Regulation Charge = Hourly Regulation Obligation Share * (sum of the Real-time Settlement Interval Regulation credits in an hour)

(b) Each Market Participant supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection shall be credited for each of its resources such that the calculated credit for each increment of Regulation provided by each resource shall be the higher of: (i) the Regulation market-clearing price; or (ii) the sum of the applicable Regulation offers for a resource determined pursuant to section 3.2.2A.1 of this Schedule, the resource-specific shoulder opportunity costs described in subsection (e) below, the resource-specific inter-temporal opportunity costs discussed in subsection (d), and the resource-specific opportunity costs discussed in subsection (e) of this section.

(c) The Office of the Interconnection shall commit resources to provide Regulation every 30 minutes, for the clock intervals of the first 30 minutes of an hour and the second 30 minutes of an hour, up to the Regulation Requirement of such Regulation Zone. The Office of the Interconnection shall select resources in merit order, taking into account the resource's mileage Regulation offer, capability Regulation offer, and estimated resource-specific opportunity cost, all converted into their performance adjusted values as further detailed in the PJM Manuals. The total Regulation market-clearing price in each Regulation Zone shall be determined in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval. The total Regulation market-clearing price shall include: (i) the mileage Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 below shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in Tariff, Attachment K-Appendix, section 1.10.1A(e).

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the resource-specific opportunity costs (in dollars) of a resource offering to sell Regulation in each regulating interval, except for hydroelectric resources, shall be equal to the area bounded by (i) Locational Marginal Price at the generation bus for the regulating resource, (ii) the resource's Final Offer, (iii) the resource's tracking ramp-rate limited expected output level if it had been

dispatched for energy in economic merit order, as further described in the PJM Manuals, and (iv) the resource's regulation set point on the energy schedule curve on which the resource is running in the PJM Interchange Energy Market. The area is divided by the resource performance score and further divided by the resource's regulation assigned megawatt to convert to dollars per megawatt.

For hydroelectric resources offering to sell Regulation in a regulating interval, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the full value of the Locational Marginal Price at that generation bus for each megawatt of Regulation capability.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the expected Locational Marginal Price at the generation bus for the hydroelectric resource and the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. Estimated opportunity costs shall be zero for hydroelectric resources for which the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those Real-time Settlement Intervals during which all available units at the hydroelectric resource were operating is higher than the actual Locational Marginal Price at the generator bus for the Real-time Settlement Interval.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating and the expected Locational Marginal Price at the generation bus for the hydroelectric resource. Estimated opportunity costs shall be zero for hydroelectric resources for which the actual Locational Marginal Price at the generator bus for the Real-time Settlement Interval is higher than the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those Real-time Settlement Intervals during which all available units at the hydroelectric resource were operating.

For the purpose of committing resources and setting Regulation market clearing prices, the Office of the Interconnection shall utilize day-ahead Locational Marginal Prices to calculate the average of the Locational Marginal Price values used in the calculation for opportunity costs for hydroelectric resources. For the purposes of settlements, the Office of the Interconnection shall

utilize the real-time Locational Marginal Prices to calculate the average of the Locational Marginal Price used in the calculation for opportunity costs for hydroelectric resources.

Opportunity costs for Economic Load Response Participant resources and regulation-only resources to provide Regulation are zero for the purpose of committing resources, setting Regulation clearing prices, and settlements.

(e) In determining the credit under subsection (b) to a Market Participant selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for (1) each Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Regulation, and (2) the two Real-time Settlement Intervals preceding the regulation commitment and the two Real-time Settlement Intervals following the regulation commitment in accordance with the PJM Manuals and below.

The unit-specific opportunity cost in dollars, incurred during the Real-time Settlement Interval, in which the Regulation obligation is fulfilled, shall be equal to the area bounded by (i) the Locational Marginal Price at the generation bus for the regulating resource, (ii) the resource's Final Offer, (iii) the generation resource's tracking ramp-rate limited expected output level if it had been dispatched in economic merit order, as further described in the PJM Manuals, and (iv) the generation resource's regulation set point, and adjusted for the performance score of the resource. Opportunity costs for Economic Load Response Participant or regulation only resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during each of the preceding two Real-time Settlement Intervals of the regulation commitment shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating Real-time Settlement Interval in order to provide Regulation and the resource's tracking expected ramp rate limited output in each of the preceding two Real-time Settlement Intervals of the regulation commitment times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in each of the preceding two Real-time Settlement Intervals of the regulation commitment and the energy offer, using the Final Offer, at the megawatt level of the Regulation set point for the resource in the initial regulating Real-time Settlement Interval, in the PJM Interchange Energy Market, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during each of the following two Real-time Settlement Intervals of the regulation commitment shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating Real-time Settlement Interval in order to provide Regulation and the resource's tracking expected ramp-rate limited output in each of the following two Real-time Settlement Intervals of the regulation commitment times, and (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in each of the following two Real-time Settlement Intervals of the regulation

commitment and the energy offer, using the Final Offer, at the megawatt level of the Regulation set point for the resource in final regulating hour, in the PJM Interchange Energy Market all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Market Participant in a Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

(g) To determine the Regulation market mileage-clearing price, the Office of the Interconnection shall adjust the submitted mileage offer for each resource in accordance with the historical performance score of that resource, and the amount of historically dispatched Regulation (mileage) calculated by the Office of the Interconnection. The maximum adjusted mileage offer of all cleared resources will set the Regulation market mileage-clearing price.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions, will be credited for Regulation mileage by multiplying the assigned MW(s) by the Regulation market mileage-clearing price, by the ratio between the requested mileage for the Regulation dispatch signal and the historic requested mileage for the Regulation dispatch signal, calculated by the Office of the Interconnection, and by the Regulation resource's performance score calculated in accordance with subsection (j) of this section. For purposes of calculating the credit for Regulation performance, if the hourly movement of the Regulation A dispatch signal equals zero, a value of 0.1 will be used in its place.

(h) The Office of the Interconnection shall divide each Regulation resource's capability offer by the historic performance score for the resource for the purposes of committing resources and setting the market clearing prices.

The Office of the Interconnection shall calculate the Regulation market capability-clearing price for each Regulation Zone by subtracting the Regulation market mileage-clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the Regulation market capability-clearing price for that market Real-time Settlement Interval.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions will be credited for Regulation capability based on the assigned MW and the capability Regulation market-clearing price multiplied by the Regulation resource's performance score calculated in accordance with subsection (j) of this section.

(i) In accordance with the processes described in the PJM Manuals, the Office of the Interconnection shall: (i) calculate inter-temporal opportunity costs for each applicable resource; (ii) include such inter-temporal opportunity costs in each applicable resource's offer to sell frequency Regulation service; and (iii) account for such inter-temporal opportunity costs in the Regulation market-clearing price.

(j) The Office of the Interconnection shall calculate each Regulation resource's performance score. The performance score shall be a function of the difference in the energy provided versus the energy requested by the Regulation signal while scaling for the number of samples. The error measured shall be the difference of the resources response and the dispatch signal, adjusted by the assigned MW and signal dispatch of the Regulation resource. The performance score is calculated using the following equations:

Performance Score = 1 - 1/n ∑ Abs (Error);

Error = Average of Abs (Abs (Response - Regulation Signal) / (0.5*Interval Average Regulation Signal + 0.5*AREG)); and

n = the number of samples in the interval
AREG = assigned regulation megawatt.

The Office of the Interconnection shall calculate a performance score for each Regulation resource for each five-minute period the Regulation resource is assigned to provide Regulation.

The historic performance score will be based on a 100 clock-hour rolling average of the Real-time Settlement Interval performance scores, with consideration of the qualification score, for resources without adequate historical data, as defined in the PJM Manuals.

Regulation resources that have a Real-time Settlement Interval performance score below 25% will be ineligible for Regulation credits for that Real-time Settlement Interval.

Regulation resources that have historical performance scores fall below 40% shall be disqualified from providing Regulation until they are able to re-qualify, as defined in the PJM Manuals.

(k) During a Market Suspension where the suspension is less than or equal to 24 consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Regulation, the resources providing Regulation at the direction of the Office of the Interconnection will be compensated based on a calculated Regulation market-clearing price. Regulation market-clearing prices for each Real-time Settlement Interval associated with such Market Suspension shall be the average of the Regulation market-clearing prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

During a Market Suspension where the suspension is greater than 24 consecutive hours, if the Office of the Interconnection is assigning Regulation, resources providing Regulation at the direction of the Office of the Interconnection will be compensated based on a calculated Regulation clearing price. The Regulation clearing price for each Real-time Settlement Interval will be determined by calculating a Regulation clearing cost for the online resources providing Regulation during the Market Suspension. The resource's Regulation clearing cost is determined by the summation of their adjusted Regulation offer and adjusted opportunity cost. The

opportunity cost will be based on the resource's cost-based offer and will be determined as follows:

> For online resources providing Regulation on a cost-based offer at the time of the Market Suspension, that cost-based offer will be used.
>
> For online resources providing Regulation on a price-based offer at the time of the Market Suspension, the Office of the Interconnection shall use the cheapest available cost-based offer based on the dispatch cost formula as defined in Operating Agreement, Schedule 1, section 6.4.1(g) using the available cost-based offers in the Office of the Interconnection system at the time of the Market Suspension.

The highest cost resource, based on this Regulation clearing cost, will set the Regulation market-clearing price for each hour of the Market Suspension.

During a Market Suspension, if the Office of the Interconnection is not assigning Regulation resources, then the Regulation market-clearing price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period and no resource-specific opportunity cost will be calculated.

During a Market Suspension, the following Regulation components for all Real-time Settlement Intervals in the Market Suspension period will be determined as follows:

(i) If the regulation performance score cannot be calculated during a Market Suspension, the historic performance score will be used for the Market Suspension period.

(ii) If the regulation mileage cannot be calculated during a Market Suspension, the mileage will be set to one (1) for the Market Suspension period.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) For each Regulation market clearing interval, the Office of the Interconnection shall conduct a Regulation three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the Regulation three-pivotal supplier test shall be capped in the interval in which they failed the test at their cost based offers as determined pursuant to Tariff, Attachment K-Appendix, section 1.10.1A(e). A Regulation supplier fails the three-pivotal supplier test in any Regulation market clearing interval in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

(b) For the purposes of conducting the three-pivotal supplier test pursuant to this section, the following applies:

(i) The Regulation three-pivotal supplier test will include in the definition of available supply all offer megawatts from resources capable of satisfying the Regulation Requirement of the PJM Region multiplied by the historic performance score of the resource for which the capability cost-based offer plus the mileage cost-based offer plus any eligible opportunity costs is no greater than 150% of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The Regulation three-pivotal supplier test will apply on a Regulation supplier basis (i.e. not a resource by resource basis) and only the Regulation suppliers that fail the three-pivotal supplier test will have their Regulation offers capped. A Regulation supplier for the purposes of this section includes corporate affiliates. Regulation from resources controlled by a Regulation supplier or its affiliates, whether by contract with unaffiliated third parties or otherwise, will be included as Regulation of that Regulation supplier. Regulation provided by resources owned by a Regulation supplier but controlled by an unaffiliated third party, whether by contract or otherwise, will be included as Regulation of that third party.

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the Regulation Requirement for the Regulation clearing interval to determine the residual supply index. Where the residual supply index for Regulation three pivotal suppliers is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 ~~Operating Reserves~~Energy Uplift.

(a) A Market Seller's pool-scheduled resources ~~capable of providing Operating Reserves~~ shall be credited as specified below for Energy Make Whole credits~~based on the applicable offer for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource~~. ~~To the extent that Tariff, Attachment K-Appendix, sections 3.2.3A, 3.2.3A.001, and 3.2.3A.01 and the parallel provision of Operating Agreement, Schedule 1, sections 3.2.3A, 3.2.3A.001, and 3.2.3A.01 does not meet the Minimum Synchronized Reserve Requirement, the Minimum Primary Reserve Requirement, and the Minimum 30-minute Reserve Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Tariff, Attachment K-Appendix, section 1.7.17 and the parallel provision of Operating Agreement, Schedule 1, section 1.7.17, and Tariff, Attachment K-Appendix, section 1.10 and the parallel provision of Operating Agreement, Schedule 1, section 1.10. In addition, the Office of the Interconnection shall schedule Operating~~

~~Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the day-ahead market.~~

(b) Day-ahead Energy Make Whole credits~~The following determination~~ shall be ~~made~~ calculated in the following manner for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for Start-up Costs and No-load Costs and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. PJM shall also (i) determine whether any resources were scheduled in the Day-ahead Energy Market to provide Black Start Sservice, Reactive Services or transfer interface control during the Operating Day because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day in order to minimize the total cost of Operating Reserves associated with the provision of such services and reflect the most accurate possible expectation of real-time operating conditions in the day-ahead model, which resources would not have otherwise been committed in the day-ahead security-constrained dispatch and (ii) report on the day following the Operating Day the megawatt quantities scheduled in the Day-ahead Energy Market for the above-enumerated purposes for the entire RTO.

Except as provided in section 3.2.3(n) below, if the total offered price for Start-up Costs (shutdown costs for Economic Load Response Participant resources) and No-load Costs and energy summed over all Day-ahead Settlement Intervals exceeds the total value summed over all Day-ahead Settlement Intervals, the difference shall be credited to the Market Seller as day-ahead Energy Make Whole credits.

However, for the Day-ahead Settlement Intervals in which the resource is scheduled to provide energy in the Operating Day and the resource actually provides energy in at least one Real-time Settlement Interval in an hour that corresponds to such scheduled Day-ahead Settlement Intervals, a resource's day-ahead ~~Operating Reserve~~Energy Make Whole credit shall be reduced by the greater of zero or the difference of the resource's d~~D~~ay-ahead ~~Operating Reserve~~Energy Make Whole t~~T~~arget and the b~~B~~alancing ~~Operating Reserve~~Energy Make Whole t~~T~~arget, as determined below.

A resource's d~~D~~ay-ahead ~~Operating Reserve~~Energy Make Whole ~~T~~target shall be determined in accordance with the following equation:

(A + B) - C

Where:

A = Start-up Costs

B = the sum of day-ahead No-load Costs and energy over the applicable Real-time Settlement Intervals that correspond with Day-ahead Settlement Intervals in which the resource is scheduled. The day-ahead No-load Costs and energy are divided by twelve to determine the cost for each Real-time Settlement Interval.

C = the sum of the day-ahead revenues calculated for each Real-time Settlement Interval that corresponds with a Day-ahead Settlement Interval in which the resource is scheduled, where the day-ahead revenue for each such Real-time Settlement Interval equals the product of the megawatt amount of energy scheduled in the Day-ahead Energy Market and the Day-ahead Price at the applicable pricing point for the resource divided by twelve.

A resource's bBalancing ~~Operating Reserve~~Energy Make Whole ~~T~~target shall be determined in accordance with the following equation:

D – (E + F)

Where:

D = the Real-time Cost, as defined in subsection 3.2.3(e-2)(ii) of this section, ~~sum of Start-up Costs and No-load Costs and the incremental cost of energy~~ summed over all Real-time Settlement Intervals that correspond to the Day-ahead Settlement Intervals in which the resource was scheduled;

E = [(the megawatt amount of energy provided in the Real-time Energy Market minus the megawatt amount of energy scheduled in the Day-ahead Energy Market) multiplied by the Real-time Price at the applicable pricing point for the resource] plus the sum of the day-ahead revenues as determined in part C of the above formula for determining the Day-ahead ~~Operating Reserve~~Energy Make Whole ~~T~~target, summed over the ~~applicable~~ Real-time Settlement Intervals that correspond to the Day-ahead Settlement Intervals in which the resource was scheduled; and

F = the sum of all Other Market ~~r~~Revenues as defined in subsection 3.2.3(e-2)(ii) of this section, ~~earned for providing Secondary Reserves, Non-Synchronized Reserves, and Reactive Services~~ over the ~~applicable~~ Real-time Settlement Intervals that correspond to the Day-ahead Settlement Intervals in which the resource was scheduled.

~~The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this section 3.2.3(b) to real-time deviations or real-time load share plus exports, pursuant to Tariff, Attachment K-Appendix, section 3.2.3(p) below, depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day. Allocation to real-time load share under this subsection (b) shall not apply to Direct Charging Energy.~~

~~(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:~~

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve credits, identified as RA Credits for Reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

~~(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.~~

(c) The sum of the foregoing credits calculated in accordance with section 3.2.3(b) plus any unallocated charges from section 3.2.3(h) and Tariff, Attachment K-Appendix, 5.1.7, and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of ~~Operating Reserves~~Energy Make Whole credits in the Day-ahead Energy Market.

(d) The cost of ~~Operating Reserves~~Energy Make Whole credits in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load ((a) net of Behind The Meter Generation expected to be operating, but not to be less than zero; and (b) excluding Direct Charging Energy), accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day and accepted Up-to Congestion Transactions in the Day-ahead Energy Market in megawatt-hours for the Operating Day at the sink of the transaction; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside such area pursuant to Tariff, Attachment K-Appendix, section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Energy Make Whole credits ~~Operating Reserves~~ in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Tariff, Schedule 6A. The cost of Energy Make Whole credits ~~Operating Reserves~~ in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load ((a) net of operating Behind The Meter Generation; and (b) excluding Direct Charging Energy) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

(e) (i) Pool-scheduled generation resources that operate for at least one Real-time Settlement Interval within the pool-scheduled commitment period are eligible for balancing Energy Make Whole credits as further detailed in this section and in the PJM Manuals. Balancing Energy Make Whole credits eligibility for Economic Load Response Participant resources is detailed in Tariff, Attachment K-Appendix, section 3.2.3(o-1) of this section. A pool-scheduled generation resource's eligibility for balancing Energy Make Whole credits begins at the first Real-time Settlement Interval of a pool-scheduled commitment. The generation resource remains eligible for balancing Energy Make Whole credits until the later of:

1) the Real-time Settlement Interval corresponding to the end of its Day-ahead Energy Market commitment or the end of its Minimum Run Time, as applicable

or

2) the Real-time Settlement Interval when the resource is no longer running under the direction of the Office of the Interconnection.

Additionally, generation resource types with no soak process in the Start-up Cost are eligible for balancing Energy Make Whole credits for a pre-commitment period prior to the first Real-time Settlement Interval of the pool-scheduled commitment to account for ramping costs. The pre-commitment period begins with the Real-time Settlement Interval when a generation resource comes online but may not begin earlier than four Real-time Settlement Intervals (20 minutes) prior to the first Real-time Settlement Interval of the pool-scheduled commitment. However, a generation resource is only eligible for this pre-commitment period if the price and megawatt quantities submitted as part of its Incremental Energy Offer, using the lesser of the Final Offer or Committed Offer as determined using the Actual MWh during the pre-commitment period, are less than or equal to the price and megawatt quantities of its Incremental Energy Offer using the Committed Offer for the first hour of the commitment. Generation resource types with a soak process in the Start-up Cost are not eligible during the pre-commitment period.

Pool-scheduled generation resources that are released by the Office of Interconnection and ramping offline are additionally eligible for balancing Energy Make Whole credits for post-commitment Real-time Settlement Intervals until the Real-time Settlement Interval that the generation resource goes offline; however, eligibility shall not extend beyond the Real-time Settlement Interval in which the resource is no longer running under the direction of the Office of Interconnection plus the number of Real-time Settlement Intervals corresponding to the allowable ramp down period for the resource type, as specified in the PJM Manuals. However, a generation resource is only eligible for this post-commitment period if the price and megawatt quantities submitted as part of its Incremental Energy Offer, using the lesser of the Final Offer or Committed Offer as determined using the Actual MWh during the post-commitment period, is less than or equal to the price and megawatt quantities of its Incremental Energy Offer using the Committed Offer for the last hour of the commitment.

~~At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following Segments: 1) the greater of their day-ahead schedules and minimum run time specified at the time of commitment (minimum down time specified at the time of commitment for Economic Load Response Participant resources); and 2) any block of Real-time Settlement Intervals the resource operates at PJM's direction in excess of the greater of its day-ahead schedule and minimum run time specified at~~

~~the time of commitment (minimum down time specified at the time of commitment for Economic Load Response Participant resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two Segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time specified at the time of commitment (minimum down time specified at the time of commitment for Economic Load Response Participant resources) and Segment 2 will include the remainder of the contiguous Real-time Settlement Intervals when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.~~

(ii) The balancing Energy Make Whole credit calculation will be conducted on a segmented basis. For each Operating Day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two Segments for each resource.

The first Segment will be defined as the greater of the applicable day-ahead commitment and Minimum Run Time specified at the time of commitment (minimum down time specified at the time of commitment for Economic Load Response Participant resources).

Further, if a generation resource is no longer running under the direction of the Office of the Interconnection within 30 minutes after the end of the first Segment, the first Segment will also include the remainder of the Real-time Settlement Intervals in which the resource operated at the direction of the Office of the Interconnection

The second Segment will be defined as any block of contiguous Real-time Settlement Intervals the resource runs under the direction of the Office of the Interconnection in excess of the first Segment.

Notwithstanding the foregoing, each Segment shall be limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

~~A Generation Capacity Resource that operates outside of its unit-specific parameters will not receive Operating Reserve Credits nor be made whole for such operation when not dispatched by the Office of the Interconnection, unless the Market Seller of the Generation Capacity Resource can justify to the Office of the Interconnection that operation outside of such unit-specific parameters was the result of an actual constraint.~~

(iii) If a Market Seller submits an offer parameter that exceeds the applicable approved parameter limit on a parameter-limited schedule for a generation resource and such parameter affects the MW dispatch level of the resource in a given settlement interval, the resource will remain eligible for the energy uplift credit calculation but shall not recover any costs incurred during the affected settlement intervals. If such parameter impacts the commitment decision in a manner that could lead to the Office of the Interconnection committing the generation resource to produce energy for longer than it otherwise would have, the resource will not be eligible for the energy uplift credit

calculation for the commitment duration. A generation resource that is the subject to an offer parameter on a parameter-limited schedule that exceeds its approved parameter limits may still be eligible for energy uplift credits if the Market Seller of such resource can justify to the Office of the Interconnection that the need to operate outside of such unit-specific parameters was the result of an actual constraint.

~~Such~~ A Market Seller shall provide to the Market Monitoring Unit and the Office of the Interconnection its request to receive ~~Operating Reserve~~ energy uplift ~~C~~credits ~~and/or to be made whole~~ for such operation, along with documentation explaining in detail the reasons for operating its resource outside of its unit-specific parameters, within thirty calendar days following the issuance of the billing statement for the Operating Day. The Market Seller shall also respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection. The Market Monitoring Unit shall evaluate such request for compensation and provide its determination of whether there was an exercise of market power to the Office of the Interconnection by no later than twenty-five calendar days after receiving the Market Seller's request for compensation. The Office of the Interconnection shall make its determination whether the Market Seller justified that it is entitled to receive ~~Operating Reserve~~ energy uplift ~~C~~credits ~~and/or be made whole~~ for such operation of its resource for the day(s) in question, by no later than thirty calendar days after receiving the Market Seller's request for compensation.

(iv) Nuclear generation resources shall not be eligible for ~~Operating Reserve~~energy uplift payments unless: 1) the Office of the Interconnection directs such resources to reduce output, in which case, such units shall be compensated in accordance with Tariff, Attachment K-Appendix, section 3.2.3(f) and the parallel provision of Operating Agreement, Schedule 1, section 3.2.3(f); or 2) the resource submits a request for a risk premium to the Market Monitoring Unit under the procedures specified in Tariff, Attachment M – Appendix, section II.B. A nuclear generation resource (i) must submit a risk premium consistent with its agreement under such process, or, (ii) if it has not agreed with the Market Monitoring Unit on an appropriate risk premium, may submit its own determination of an appropriate risk premium to the Office of the Interconnection, subject to acceptance by the Office of the Interconnection, with or without prior approval from the Commission.

(e-1) The Tracking Ramp Limited Desired (TRLD) metric is used in the calculation of balancing Energy Make Whole credits and generator deviation charges as a representation of the level at which the resource would be desired if operating as requested by the Office of the Interconnection. There are two Tracking Ramp Limited Desired metrics, one measured in MW (power) and the other measured in MWh (energy), each of which are calculated as described below and as further detailed in the PJM Manuals. The Tracking Ramp Limited Desired MWh (energy) calculated for each Real-time Settlement Interval shall be used in the calculation of balancing Energy Make Whole credits and generator deviations. The Tracking Ramp Limited Desired MWh (energy) value represents the expected energy produced between the start of the Real-time Settlement Interval and the end of the Real-time Settlement Interval.

For purposes of this Tariff, Attachment K-Appendix, section 3.2.3, the minimum operating limit used herein shall be the Economic Minimum unless the Office of the Interconnection has declared Minimum Generation Emergency conditions, in which case it shall be the emergency minimum. Also, the maximum operating limit shall be the Economic Maximum unless the Office of the Interconnection has declared Maximum Emergency conditions, in which case it shall be the emergency maximum.

(i) Tracking Ramp Limited Desired MW (power) is an adjusted metric that accounts for the impact of Regulation and reserve assignments or manual dispatch instructions.

The Tracking Ramp Limited Desired MW (power) calculation starts at time t_0, which is when a generation resource is first expected by the Office of Interconnection to be online or when a generation resource is dispatchable, while honoring soak time differences, as further detailed in the PJM Manuals.

The Tracking Ramp Limited Desired MW (power) metric will be calculated as follows. For the Real-time Settlement Interval equal to t_0,

If a generation resource does not have a soak process and is directed to come online as soon as possible,

TRLD MW (power) = 0

Otherwise,
TRLD MW (power)
= Max [Min (LMP Desired MW, Dispatch MW), Tracking Desired Economic Minimum]

Where:
LMP Desired MW = the generation resource's expected output level based on its Final Offer at the Real-time Locational Marginal Price from the dispatch run at the applicable pricing point
Dispatch MW = energy dispatch signal MW from the dispatch run
Tracking Desired Economic Minimum = the generation resource's minimum operating limit, as specified in Tariff, Attachment K-Appendix, section 3.2.3(e-1), unless any of the following conditions occur,

- If a resource is requested to increase output due to a transmission constraint or other reliability issue, Tracking Desired Economic Minimum = the lower limit from the manual dispatch instruction as directed by the Office of the Interconnection.

- If the resource's minimum operating limit increases by more than 5% of the resource's minimum operating limit at the time of commitment, the minimum operating limit at the time of commitment will be used.

For each Real-time Settlement Interval after the resource's initial start time, t_0, Tracking Ramp Limited Desired MW (power) shall be calculated as follows:

$$\text{TRLD MW}_t \text{ (power)} = \text{TRLD MW}_{t-1} \pm \text{Ramp}_t$$

Where:

t = Start time of Real-time Settlement Interval for which the metric is being calculated

Ramp = Increase or decrease in MW calculated using the Real-time Locational Marginal Price from the dispatch run at the applicable pricing point, the resource's Final Offer, and the ramp rate parameters. The increase or decrease in MW is restricted by the most limiting of the following parameters among the ramp rate, the Tracking Desired Economic Minimum, and the Tracking Desired Economic Maximum, where:

Tracking Desired Economic Minimum = defined above in the calculation for TRLD MW_{t0}

Tracking Desired Economic Maximum = the generation resource's maximum operating limit unless any one of the following conditions occur:

- If a resource is requested to decrease output due to a transmission constraint or other reliability issue, Tracking Desired Economic Maximum = the upper limit from the manual dispatch instruction as directed by the Office of the Interconnection.

- If a resource's maximum operating limit decreases by more than 5% of the resource's maximum operating limit at the time of commitment, the maximum operating limit at the time of commitment will be used.

The Tracking Ramp Limited Desired MW (power) value will be further adjusted, as specified below, if the resource has a regulation or reserve assignment and is unable to provide such assignment while generating the initial Tracking Ramp Limited Desired MW due to the resource's applicable operating parameters.

- If the Tracking Ramp Limited Desired MW is above the highest MW point at which the resource can provide the Regulation or reserve assignments, the Tracking Ramp Limited Desired MW will be lowered to the highest point at which it can provide the assignment(s) based on the resource's applicable operating parameters.

- If the Tracking Ramp Limited Desired MW is below the lowest MW point at which the resource can provide the Regulation assignment, the Tracking Ramp Limited Desired MW will be increased to the lowest point at which it can provide the regulation assignment based on the resource's applicable operating parameters.

This adjusted Tracking Ramp Limited Desired MW value is used in calculating the Tracking Ramp Limited Desired MW (power) for subsequent intervals.

(ii) An unadjusted Tracking Ramp Limited Desired MW (power) that excludes the impact of Regulation and reserve assignments or manual dispatch instructions is also calculated for conversion to an unadjusted Tracking Ramp Limited Desired MWh (energy) metric which is used in the Other Market Revenue and Opportunity Cost Owed calculations described in subsection 3.2.3(e-2)(i). The unadjusted Tracking Ramp Limited Desired MW (power) metric will be calculated as follows.

For the Real-time Settlement Interval equal to t_0, the unadjusted Tracking Ramp Limited Desired MW (power) equals the Tracking Ramp Limited Desired MW $(power)_{t0}$ as calculated in subsection (i) directly above excluding the impact of regulation and reserve assignments or manual dispatch instructions.

For each Real-time Settlement Interval after the start time, t_0, the unadjusted Tracking Ramp Limited Desired MW (power) shall be calculated as follows:

$$\text{unadjusted TRLD } MW_t \text{ (power)} = \text{unadjusted TRLD } MW_{t-1} \pm Ramp_t$$

Where:

t = Start time of Real-time Settlement Interval for which the metric is being calculated

Ramp = Increase or decrease in MW calculated using the Real-time Locational Marginal Price from the dispatch run at the applicable pricing point, the resource's Final Offer, and the ramp rate parameters. The increase or decrease in MW is restricted by the most limiting parameter among the ramp rate, the unadjusted economic minimum, and the unadjusted economic maximum, where:

unadjusted economic minimum = minimum operating limit for the Real-time Settlement Interval unless such minimum operating limit increased by more than 5% of the resource's minimum operating limit at the time of commitment, in which case the minimum operating limit at the time of commitment shall be used.

unadjusted economic maximum = maximum operating limit for the Real-time Settlement Interval unless such maximum operating limit decreased by more than 5% of the resource's maximum operating limit at the time of commitment, in which case the maximum operating limit at the time of commitment shall be used.

(iii) The Tracking Ramp Limited Desired MW (power) calculations in Tariff, Attachment K-Appendix, section 3.2.3(e-1)(i) and (ii) above will continue until the resource goes offline; however, if a generation resource trips or is taken offline at the

request of the Market Seller prior to the later of the end of the Day-ahead Energy Market commitment or the end of the Minimum Run Time, the values will continue to be calculated per the calculations defined above until the later of the end of the Day-ahead Energy Market commitment or the end of the Minimum Run Time.

Further, once the Office of the Interconnection releases a generation resource to go offline, provided that the resource actually goes offline following such direction, the Tracking Ramp Limited Desired MW shall be calculated using only the ramp down parameters such that the Tracking Ramp Limited Desired MW is incrementally ramped down to its minimum output, irrespective of the real-time LMP. During this time period, the unadjusted Tracking Ramp Limited Desired MW (power) will equal the Tracking Ramp Limited Desired MW (power) unless the resource has been manually dispatched offline, in which case the unadjusted Tracking Ramp Limited Desired MW (power) will continue as specified above in Tariff, Attachment K-Appendix, section 3.2.3(e-1)(ii) until the manual dispatch instruction ends.

TRLD MW_t (power) =

Max (TRLD MW_{t-1} – Down $Ramp_t$, Tracking Desired Economic $Minimum_t$)

Where Down Ramp = Decrease in MW utilizing the resource's down ramp rate parameter.

(iv) The Tracking Ramp Limited Desired MW (power) and unadjusted Tracking Ramp Limited Desired MW (power) metrics will be converted to the Tracking Ramp Limited Desired MWh (energy) metrics that shall be used in the calculation of balancing Energy Make Whole credits and generator deviations. For all Real-time Settlement Intervals prior to the start time of the Tracking Ramp Limited Desired MW (power) calculations, t_0 as defined above, both the Tracking Ramp Limited Desired MWh (energy) and the unadjusted Tracking Ramp Limited Desired MWh (energy) shall be equal to the resource's Actual MWh for that Real-time Settlement Interval. For purposes of this section, Actual MWh equals the Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Tariff, Attachment K-Appendix, section 3.1A and parallel provisions in Operating Agreement, Schedule 1, section 3.1A.

For each Real-time Settlement Interval after the Office of the Interconnection releases a generation resource to go offline and the resource's Actual MWh is below the minimum operating limit, the Tracking Ramp Limited Desired MWh (energy) and the unadjusted Tracking Ramp Limited Desired MWh (energy) shall be equal to Actual MWh of the resource.

For all other Real-time Settlement Intervals, the Tracking Ramp Limited Desired MWh (energy) shall equal the expected energy produced between the start of the Real-time Settlement Interval and the end of the Real-time Settlement Interval based on the Tracking Ramp Limited Desired MW (power) at the start and at the end of the Real-time Settlement Interval and the resource's ramping capability, as further described in the PJM

Manuals. The unadjusted Tracking Ramp Limited Desired MWh (energy) shall equal the expected energy produced between the start of the Real-time Settlement Interval and the end of the Real-Time Settlement Interval based on the unadjusted Tracking Ramp Limited Desired MW (power) at the start and at the end of the Real-time Settlement Interval and the resource's ramping capability, as further described in the PJM Manuals.

(v) The Tracking Ramp Limited Desired MW (power) and MWh (energy) values described above in subsections Tariff, Attachment K-Appendix, section 3.2.3(e-1)(i) and (ii), as may be qualified by (iii), and (iv) of this section may be further adjusted as described in the PJM Manuals to account for instances where the Office of the Interconnection is unable to dispatch the system using the real-time security constrained economic dispatch system and/or where the real-time security-constrained economic dispatch application is providing dispatch signals inconsistent with the resource's offer data, or other abnormal dispatch scenarios.

(e-2) For generating resources, balancing Energy Make Whole c~~C~~redits received pursuant to this section shall be equal to the lesser of the Tracking Balancing Energy Make Whole Credit, as calculated in Step 1 below in Tariff, Attachment K-Appendix, section 3.2.3(e-2)(i), and the Actual Balancing Energy Make Whole Credit, as calculated in Step 2 below in Tariff, Attachment K-Appendix, section 3.2.3(e-2)(ii), for each Segment in the Operating Day, except as provided in this Tariff, Attachment K-Appendix, section 3.2.3(m). Balancing Energy Make Whole credits for Economic Load Response Participant resources shall be equal to the credits as determined in Tariff, Attachment K-Appendix, section 3.3.A~~positive difference between a resource's Total Operating Reserve Offer, and the total value of the resource's energy in the Day-ahead Energy Market plus any credit or charge for quantity deviations, at PJM dispatch direction (excluding quantity deviations caused by an increase in the Market Seller's Real-time Offer), from the Day-ahead Energy Market during the Operating Day at the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for Segment 2 shall exclude start up (shutdown costs for Economic Load Response Participant resources) costs for generation resources~~.

~~Except as provided in section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to section 3.2.3(b), and less the absolute value of any negative Synchronized Reserve lost opportunity cost credit, as determined in section 3.2.3A(f)(iv) below, and less the absolute value of any negative Non-Synchronized Reserve lost opportunity cost credit determined in section 3.2.3.A.001(d)(iii) below, and less any amounts credited for providing Reactive Services as specified in section 3.2.3B, and less the absolute value of any negative Secondary Reserve lost opportunity cost credit, as determined in section 3.2.3A.01(f)(iv) below, and plus the sum of the Market Revenue Neutrality Offsets for Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve, shall be credited to the Market Seller.~~

~~Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding Real-time Settlement Interval(s) in which the~~

~~Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each Real-time Settlement Interval the unit operates in condensing and generation mode.~~

(i) Step 1: Calculate Tracking Balancing Energy Make Whole credit for the Segment using Tracking Ramp Limited Desired MWh.

Tracking Balancing Energy Make Whole Credit = A – B

Where

A = $-1 \times \sum_t$ Tracking Balancing Net Revenue$_t$

Where t = the eligible Real-time Settlement Intervals in the applicable Segment

B = Day-ahead Energy Make Whole Credit as determined pursuant to section 3.2.3(b) if the Segment is the first Segment. For all other Segments, B = 0.

Tracking Balancing Energy Make Whole Credit shall not be less than zero.

The Tracking Balancing Net Revenue for each Real-time Settlement Interval in the Segment shall be calculated in accordance with the following equation:

Tracking Balancing Net Revenue$_t$ = (DA Revenue$_t$ + Balancing Revenue$_t$ + Other Market Revenue$_t$ + Opportunity Cost Owed$_t$) - Real-time Cost$_t$

Where

t = the Real-time Settlement Interval

DA Revenue = Day-ahead Energy Market Revenue for the Real-time Settlement Interval in accordance with the following equation:

Day-ahead Scheduled MWh × Day-ahead LMP

Balancing Revenue = Balancing Energy Market Revenue in accordance with the following equation:

(Tracking Ramp Limited Desired MWh ─ Day-ahead Scheduled MWh) × Real-time LMP ─ Company Responsible Negative Revenues

Where: Company Responsible Negative Revenues = any negative balancing revenues in excess of the Day-ahead Energy Market revenue that results from the Market Participant's actions reducing the resource's flexibility as further specified in the PJM Manuals. This is calculated as:

MW unavailable due to limited flexibility × Min (Day-ahead LMP ─ Real-Time LMP, 0)

Other Market Revenue = SR + SecR + NSR + Reactive + LOC + Reg

Where
SR = any potential credits for providing Synchronized Reserve determined in accordance with the credit calculations in Tariff, Attachment K-Appendix, section 3.2.3A(b) less the resource's Synchronized Reserve offer price, in dollars, included in the resource's Synchronized Reserve potential lost opportunity cost credit in Tariff, Attachment K-Appendix, section 3.2.3A(f)(iv).

SecR = any potential credits for providing Secondary Reserve determined in accordance with the credit calculations in Tariff, Attachment K-Appendix, section 3.2.3A.01(b)

NSR = any amounts credited for providing Non-Synchronized Reserve as specified in Tariff, Attachment K-Appendix, section 3.2.3A.001(b)

Reactive = any potential credits for providing Reactive Services determined in accordance with the credit calculations in Tariff, Attachment K-Appendix, section 3.2.3B

LOC = any potential lost opportunity cost credits determined in Tariff, Attachment K-Appendix, sections 3.2.3(f) – 3.2.3(f-6).

Reg = any potential Regulation opportunity cost amounts determined in accordance with the calculations for use in settlements in Tariff, Attachment K-Appendix, section 3.2.2.

Opportunity Cost Owed = the sum of the potential opportunity costs owed for Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve as determined in accordance with Sections 3.2.3A(f)(iv), 3.2.3A.001(d)(iii) and 3.2.3A.01(f)(iv), respectively.

For the purposes of the above Other Market Revenue and Opportunity Cost Owed calculations, the potential credits and costs are determined using the calculations referenced above and the assumption that the resource was increased or decreased from the unadjusted Tracking Ramp Limited Desired MWh in order to provide the assignment or PJM directed MW as further described in the PJM Manuals.

Real-time Cost = (Incremental Offer + No Load Cost + Start-Up Cost)
Where

Incremental Offer = Real-time incremental energy offer, in dollars, based on the area under the incremental energy offer curve calculated using the Tracking Ramp Limited Desired MWh

No Load = Real-time No-load Cost

Start-Up = Real-time Start-Up Cost, if it is a Real-time Settlement Interval in the first Segment

The offer used for calculating Real-time Cost shall be the lesser of the Committed Offer or Final Offer based on the offer with the lowest total cost for the hour.

The above Balancing Revenue and Real-time Cost calculations shall be further modified for Real-time Settlement Intervals preceding the start of the commitment for generation resource types with no soak process in the Start-up Cost by capping the Tracking Ramp Limited Desired MWh (energy) at the minimum operating limit for such interval.

The above Balancing Revenue and Real-time Cost calculations shall be reduced by the costs incurred and revenues received in the applicable Real-time Settlement Intervals for generation resource types with a soak process in the Start-up Cost when the Tracking Ramp Limited Desired MWh (energy) indicate the unit is not dispatchable by the Office of the Interconnection during a Real-time Settlement Interval when it was scheduled to be dispatchable since those costs and revenues may already be included in the Start-Up Cost as further defined in the PJM Manuals.

During Real-time Settlement Intervals where a Flexible Resource is self-scheduled and was committed by the Office of the Interconnection in the Day-ahead Energy Market for the same Real-time Settlement Interval, the above calculation will use the Tracking Balancing Net Revenues that the resource would have received if it had followed PJM real-time commitment instructions and remained offline; provided that if the unit is taken over by company to run as self-scheduled prior to the Minimum Run Time of a pool scheduled commitment elapsing, this shall only apply to those Real-time Settlement Intervals beyond the Minimum Run Time.

(ii) Step 2: Calculate balancing Energy Make Whole credits for the Segment using Actual MWh.

Actual Balancing Energy Make Whole Credit = A – B

Where

$A = -1 \times \sum_t$ Actual Balancing Net Revenue$_t$

Where t = the eligible Real-time Settlement Intervals in the applicable Segment

B = Day-ahead Energy Make Whole Credit as determined pursuant to section 3.2.3(b) if the Segment is the first Segment; else, 0

Actual Balancing Energy Make Whole Credit shall not be less than zero.

The Actual Balancing Net Revenue for each Real-time Settlement Interval in the Segment shall be calculated in accordance with the following equation. For purposes of this section, the Actual MWh equals the Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Tariff, Attachment K-Appendix, section 3.1A.

Actual Balancing Net Revenue$_t$ = (DA Revenue$_t$ + Balancing Revenue$_t$ + Other Market Revenue$_t$) - Real-time Cost$_t$

Where
t = the Real-time Settlement Interval

DA Revenue = Day-ahead Energy Market Revenue for the Real-time Settlement Interval in accordance with the following equation:

Day-ahead Scheduled MWh × Day-ahead LMP

Balancing Revenue = Balancing Energy Market Revenue for the Real-time Settlement Interval in accordance with the following equation:

(Actual MWh – Day-ahead Scheduled MWh) × Real-time LMP ― Company Responsible Negative Revenues

Where: Company Responsible Negative Revenues = any negative balancing revenues in excess of the DA revenue based on the Market Participant's actions reducing flexibility as further specified in the PJM Manuals. This is calculated as:

MW unavailable due to limited flexibility × Min (Day-ahead LMP ― Real-Time LMP, 0)

Other Market Revenue = SR + SecR + NSR + Reactive + LOC + Reg

Where:
SR = any amounts credited for providing Synchronized Reserve equal to the credits as determined in Tariff, Attachment K-Appendix, section 3.2.3A(b) less the resource's Synchronized Reserve offer price, in dollars, included in the resource's Synchronized Reserve lost opportunity cost credit calculation in Tariff, Attachment K-Appendix, section 3.2.3A(f)(iv)

SecR = any amounts credited for providing Secondary Reserve as determined in Tariff, Attachment K-Appendix, section 3.2.3A.01 (b)

NSR = any amounts credited for providing Non-Synchronized Reserve as determined in Tariff, Attachment K-Appendix, section 3.2.3A.001(b)

Reactive = any amounts credited for providing Reactive Services as determined in Tariff, Attachment K-Appendix, section 3.2.3B

LOC = any lost opportunity costs credits as determined in Tariff, Attachment K-Appendix, sections 3.2.3(f) – 3.2.3(f-6); and

Reg =any Regulation opportunity cost amounts as calculated for purposes of settlements in Tariff, Attachment K-Appendix, section 3.2.2

Real-time Cost = (Incremental Offer + No Load + Start-Up)

Incremental Offer = Real-time incremental energy offer, in dollars, based on the area under the incremental energy offer curve calculated using the Actual MWh

No Load = Real-time No-load Cost

Start-Up = Real-time Start-Up Cost, if it is within the first Segment

The offer used for calculating Real-time Cost shall be the Final Offer for the hour.

The above Balancing Revenue and Real-time Cost calculations shall be reduced by the costs incurred and revenues received in the applicable Real-time Settlement Intervals for generation resource types with a soak process in the Start-up Cost when the Actual MWh indicate the resource is not dispatchable by the Office of the Interconnection during a Real-time Settlement Interval when it was scheduled to be dispatchable by the Office of the Interconnection since those costs and revenues may already be included in the Start-Up Cost as further defined in the PJM Manuals.

The above Balancing Revenue and Real-time Cost calculation shall be further modified for Real-time Settlement Intervals preceding the start of the commitment for generation resource types with no soak process in the Start-up Cost, by capping the Actual MWh at the minimum operating limit for each such interval.

(iii) In the event of a real-time Market Suspension, if the Office of the Interconnection and the Market Monitoring Unit determine that the generation resource was not following dispatch instructions, the generation resource shall be ineligible for balancing Energy Make Whole credits. If the generation resource is eligible during a real-time Market Suspension, the balancing Energy Market Whole credit shall be equal to the actual balancing Energy Make Whole credit, as determined in subsection 3.2.3(e-2)(ii) of this section.

(iv) A price-sensitive pool-scheduled import transaction shall receive balancing Energy Make Whole credits equal to the positive difference between a transaction's offer, and the total value of the transaction's energy in the Day-ahead Energy Market plus any credit or charge for quantity deviations from the Day-ahead Energy Market at the real-

time LMP(s) applicable to the sink of the transaction summed over all Real-time Settlement Intervals in the Operating Day.

(f) A Market Seller of a unit not defined in subsection (f-1), (f-2), or (f-4) hereof (or self-scheduled, if operating according to Tariff, Attachment K-Appendix, section 1.10.3(c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the LOC Deviation times (B) the Locational Marginal Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C. A Market Seller of a unit defined in subsection (f-1), (f-2), (f-3), (f-4), or (f-5) that is reduced using a generator output constraint to honor a stability limitation is not eligible for credits under this section 3.2.3(f) for the MWh reduction associated with honoring the stability limit. If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.11.6, where the suspension is greater than twenty-four (24) consecutive hours, resources will not be compensated for lost opportunity costs.

(f-1) With the exception of Market Sellers of Flexible Resources that submit a Real-time Offer greater than their resource's Committed Offer in the Day-ahead Energy Market, a Market Seller of a Flexible Resource shall be compensated for lost opportunity cost, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described in section 3.2.3 (f).

(ii) If the unit is scheduled to produce energy in the Day-ahead Energy Market for a Day-ahead Settlement Interval, but the unit is not called on by the Office of the Interconnection and does not operate in the corresponding Real-time Settlement Interval(s), then the Market Seller shall be credited in an amount equal to the higher of:

1) the product of (A) the amount of megawatts committed in the Day-ahead Energy Market for the generating unit, and (B) the Real-time Price at the generation bus for the generating unit, minus the sum of (C) the Total Lost Opportunity Cost Offer plus No-load Costs, plus (D) the Start-up Cost, divided by the Real-time Settlement Intervals committed for each set of

contiguous hours for which the unit was scheduled in Day-ahead Energy Market. This equation is represented as (A*B) - (C+D). The startup cost, (D), shall be excluded from this calculation if the unit operates in real time following the Office of the Interconnection's direction during any portion of the set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market, or

2) the Real-time Price at the unit's bus minus the Day-ahead Price at the unit's bus, multiplied by the number of megawatts committed in the Day-ahead Energy Market for the generating unit.

(f-2) A Market Seller of a hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Tariff, Attachment K-Appendix, section 1.10.3(c) hereof), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-4) A Market Seller of a wind or solar generating unit, Hybrid Resource or Energy Storage Resource Model Participant that is pool-scheduled or self-scheduled, has SCADA capability to transmit and receive instructions from the Office of the Interconnection, has provided data and established processes to follow PJM basepoints pursuant to the requirements for wind or solar generating units, Hybrid Resource or Energy Storage Resource Model Participant as further detailed in this Agreement, the Tariff and the PJM Manuals, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the LOC Deviation

times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C. An Energy Storage Resource Model Participant or a Hybrid Resource instructed to increase charging at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, shall be compensated for the increase in charging in the same manner as provided in sections 3.2.3(e). A unit in the Energy Storage Resource Participation Model or a Hybrid Resource instructed to reduce charging at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, is not eligible for compensation under section 3.2.3(f-4).

(f-5) If a Market Participant of an Energy Storage Resource Model Participant or a Hybrid Resource believes that the above calculations in this section 3.2.3 do not accurately compensate the Market Participant for opportunity costs associated with following PJM manual dispatch instructions to modify a unit's charging or discharging due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Participant will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Participant. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Participant accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-6) (i) A Market Seller of a pool-scheduled resource or a dispatchable self-scheduled resource shall receive Dispatch Differential Lost Opportunity Cost credits as calculated under subsection (iv) below if the resource is dispatched to provide energy in the Real-time Energy Market, provided such resource is not committed to provide real-time ancillary services (Regulation, reserves, reactive service) or instructed to reduce or suspend output due to a transmission constraint or other reliability issue pursuant to Tariff, Attachment K-Appendix, section 3.2.3(f-1) through Tariff, Attachment K-Appendix, section (f-4).

(ii) PJM will calculate the revenue above cost for the pricing run for each Real-time Settlement Interval in accordance with the following equation:

(A x B) - C

Where:

A = the resource's expected output level based on its resource parameters at the Real-time Price at the applicable pricing point;

B = the Real-time Price at the applicable pricing point; and

C = the sum of the resource's Real-time Energy Market offer integrated under the Final Offer for the resource's expected output level based on its resource parameters at the Real-time Price at the applicable pricing point.

(iii) PJM will calculate the revenue above cost for the dispatch run for each Real-time Settlement Interval in accordance with the following equation:

(greater of A and B) – (lesser of C and D)

Where:

A = the product of the amount of megawatts of energy dispatched in the Real-time Energy Market dispatch run for the resource in that Real-time Settlement Interval and the Real-time Price at the applicable pricing point;

B = the product of the amount of megawatts of energy the resource actually provided in that Real-time Settlement Interval and the Real-time Price at the applicable pricing point;

C = the resource's Real-time Energy Market offer integrated under the Final Offer for the amount of megawatts dispatched in the Real-time Energy Market dispatch run;

D = the resource's Real-time Energy Market offer integrated under the Final Offer for the amount of megawatts the resource actually provided in that Real-time Settlement Interval.

(iv) The Dispatch Differential Lost Opportunity Cost credit shall equal the greater of (A) the difference between the revenue above cost based on the pricing run determined in subsection (f-6)(ii) and the revenue above cost based on the dispatch run determined in subsection (f-6)(iii) or (B) zero.

(v) For each hour in an Operating Day, the total cost of the Dispatch Differential Lost Opportunity Cost credits shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load ((a) net of operating Behind The Meter Generation, but not to be less than zero; and (b) excluding Direct Charging Energy) in the PJM Region, served under Network Transmission Service, in megawatt-hours; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Tariff, Attachment K-Appendix, section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(g) The sum of the foregoing credits in Tariff, Attachment K-Appendix, section 3.2.3(f-~~1~~) through Tariff, Attachment K-Appendix, section 3.2.3(f-54), plus any cancellation fees paid in accordance with Tariff, Attachment K-Appendix, section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, plus any balancing Energy Make Whole Credits paid to pool-scheduled import transactions, less any payments received from another Control Area for ~~Operating Reserves~~energy uplift shall be

allocated to each Market Participant's pro rata share of the daily total of hourly deviations in the RTO region, determined pursuant to Tariff, Attachment K-Appendix, section 3.2.3(h). If the Office of the Interconnection declares a Market Suspension, per Tariff, Attachment K-Appendix, section 1.11.6, the Office of the Interconnection shall allocate the charges to the pro rata share of the sum of its (i) deliveries of energy to load ((a) net of operating Behind The Meter Generation, but not to be less than zero; and (b) excluding Direct Charging Energy) in the PJM Region, served under Network Transmission Service, in megawatt-hours; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Tariff, Attachment K-Appendix, section 1.12.~~the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.~~

(h) ~~The cost of Operating Reserves for the Real-time Energy Market for each Operating Day, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Tariff, Schedule 6A, shall be allocated and charged to e~~Each Market Participant's ~~based on their~~ daily total of hourly deviations are determined in accordance with the following equation:

$$\sum_h (A + B + C)$$

Where:

h = the hours in the applicable Operating Day;

A = For each Real-time Settlement Interval in an hour, the sum of the absolute value of the withdrawal deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy withdrawals (net of operating Behind The Meter Generation) in the Real-time Energy Market, except as noted in subsection (h)(ii) below and in the PJM Manuals divided by the number of Real-time Settlement Intervals for that hour. The summation of each Real-time Settlement Interval's withdrawal deviation in an hour will be the Market Participant's total hourly withdrawal deviations. Market Participant bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Tariff, Attachment K-Appendix, section 1.12 are not included in the determination of withdrawal deviations;

B = For each Real-time Settlement Interval in an hour, the sum of the absolute value of generation deviations (in MW and not including deviations in Behind The Meter Generation) as determined in subsection (o) divided by the number of Real-time Settlement Intervals for that hour;

C = For each Real-time Settlement Interval in an hour, the sum of the absolute value of the injection deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy injections in the Real-time Energy Market divided by the number of Real-time Settlement Intervals for that hour. The summation of the injection deviations for each Real-time Settlement Interval in an hour

will be the Market Participant's total hourly injection deviations. The determination of injection deviations does not include generation resources.

The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Tariff, Attachment K-Appendix, section 3.1A shall be used in determining the real-time withdrawal deviations, generation deviations and injection deviations ~~used to calculate Operating Reserve~~ under this subsection (he).

~~The costs associated with scheduling of units for Black Start service or testing of Black Start Units shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Tariff, Schedule 6A.~~

The foregoing notwithstanding, netting deviations shall be allowed for each Real-time Settlement Interval in accordance with the following provisions:

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions, which include the components referenced in Tariff, Attachment K-Appendix, section 3.2.3(d) regarding the cost of Energy Make Whole credits in the Day-ahead Energy Market, at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

(iv) Bilateral transactions inside the PJM Region, as defined in Tariff, Attachment K-Appendix, section 1.7.10, will not be included in the determination of supply or demand deviations.

Deviations as calculated above shall be deviations in the RTO region and shall be subject to charges for the RTO region determined in accordance with Tariff, Attachment K-Appendix, section 3.2.3(q)(iii). Furthermore, d~~D~~eviations that occur within a single Zone shall be associated with the Eastern or Western ~~R~~region, as defined in Tariff, Attachment K-Appendix, section 3.2.3(q) below, and shall be subject to charges determined for such~~the~~ region~~al balancing Operating Reserve rate determined~~ in accordance with Tariff, Attachment K-Appendix, section 3.2.3(q)(iii). Deviations at a hub shall be associated with the Eastern or Western ~~R~~region if all the buses that define the hub are located in the region. Deviations at an Interface Pricing Point shall be associated with whichever region, the Eastern or Western ~~R~~region, with which the

majority of the buses that define that Interface Pricing Point are most closely electrically associated. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to charges determined for such region in accordance with Tariff, Attachment K-Appendix, section 3.2.3(q)(iii)~~the regional balancing Operating Reserve rate~~. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by buses that are wholly contained within the same Zone.

~~The foregoing notwithstanding, netting deviations shall be allowed for each Real-time Settlement Interval in accordance with the following provisions:~~

~~(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.~~

~~(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions, which include the components referenced in section 3.2.3(d) regarding the cost of Operating Reserves in the Day-ahead Energy Market, at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.~~

~~(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.~~

~~(iv) Bilateral transactions inside the PJM Region, as defined in Operating Agreement, Schedule 1, section 1.7.10, will not be included in the determination of Supply or Demand deviations.~~

(i) At the end of each Operating Day, Market Sellers shall be credited for Condense Startup Cost and Condense Energy Use times the real-time LMP for synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in section 3.2.3(i) shall be the cost of ~~Operating Reserves~~energy uplift for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for the PJM Region.

(k) The cost of ~~Operating Reserves~~energy uplift for synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load ((a) net of operating Behind The Meter Generation, but not to be less than zero; and (b) excluding Direct Charging Energy) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Tariff, Attachment K-Appendix, section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared ("Maximum Generation Emergency Alert"); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the ~~Operating Reserves~~Energy Make Whole credit otherwise provided by section 3.2.3.(b) or section 3.2.3(e) in connection with market-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as "MaxGen Conditions"). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Operating Agreement, Schedule 2, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Tariff, Attachment K-Appendix, section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Tariff, Attachment K-Appendix, section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Tariff, Attachment K-Appendix, section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh and greater than the Market Seller's lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for ~~Operating Reserves~~Energy Make Whole. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for ~~Operating Reserves~~Energy Make Whole for such Operating Day pursuant to section 3.2.3(e) plus the Real-time Energy Market revenues for the Real-time Settlement Intervals that the offer is economic divided by the megawatt hours of energy provided during the Real-time Settlement Intervals that the offer is economic. The Real-time Settlement Intervals that the offer is economic shall be: (i) the Real-time Settlement Intervals that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the Real-time Settlement Intervals in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any Real-time

Settlement Intervals required due to the ~~m~~Minimum ~~r~~Run ~~t~~Time or other operating constraint of the unit, and (iii) for any unit with a M~~m~~inimum R~~r~~un ~~t~~Time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price for a market-based offer is greater than $1,000/MWh and greater than the Market Seller's lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Energy Make Whole~~Operating Reserves~~. If notice of a MaxGen Condition is provided after 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Energy Make Whole~~Operating Reserves~~ determined in accordance with section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Energy Make Whole~~Operating Reserves~~ determined in accordance with section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Energy Make Whole ~~Operating Reserves~~ for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Energy Make Whole ~~Operating Reserves~~ for such Operating Day pursuant to section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Energy Make Whole ~~Operating Reserves~~ payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) ~~Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled~~All generation resources ~~that do not follow dispatch~~ shall be assessed ~~balancing Operating Reserve~~ deviations in accordance with the calculations described below and in the PJM Manuals.

~~The Office of the Interconnection shall calculate a ramp-limited desired MW value for generation resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:~~

(i) real-time economic minimum <= 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

$$Ramp_Request_t = {(Dispatchtarget_{t-1} - AOutput_{t-1})}/{(LAtime_{t-1})}$$

$$RL_Desired_t = AOutput_{t-1} + (Ramp_Request_t * Case_Eff_time_{t-1})$$

where:

1. Dispatchtarget = Dispatch Signal for the previous approved Dispatch case
2. AOutput = Unit's achievable target MW at case solution time as defined in the PJM Manuals
3. LAtime = Dispatch look ahead time
4. Case_Eff_time = Time between signal changes
5. RL_Desired = Ramp-limited desired MW

To determine if a generation resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the dispatch signal or the actual output and ramp-limited desired MW value for each Real-time Settlement Interval. If the dispatch signal and the ramp-limited desired MW for the resource are unavailable, the Office of the Interconnection will determine the unit's MW off dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the dispatch LMP Desired MW for each Real-time Settlement Interval.

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and dispatch signal, or if its % off dispatch is <= 10, or its Real-time Settlement Interval MWh is within 5% of the Real-time Settlement Interval ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined for each Real-time Settlement Interval in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – Day-Ahead MWh.

- ~~A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – dispatch LMP Desired MW.~~

- ~~Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – Ramp-Limited Desired MW.~~

- ~~If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and dispatch LMP Desired MWh for the Real-time Settlement Interval is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: Real time Settlement Interval MWh – dispatch LMP Desired MWh.~~

- ~~If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh – Ramp-Limited Desired MW. If deviation value is within 5% of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.~~

- ~~If a resource is not following dispatch and its % off Dispatch is > 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: Real time Settlement Interval MWh – dispatch LMP Desired MWh.~~

- ~~If a resource is not following dispatch, and the resource has tripped, for the Real-time Settlement Interval the resource tripped and the Real-time Settlement Intervals it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh – Day-Ahead MWh.~~

- ~~For resources that are not dispatchable in both the Day-ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh - Day-Ahead MWh.~~

Generation resource deviations are calculated as the difference between a resource's Actual MWh, (which for purposes of this section is defined as the Revenue Data for Settlements), and Tracking Ramp Limited Desired MWh for each Real-time Settlement Interval except for the scenarios where day-ahead scheduled MWh are used in the calculation as defined below.

A generation resource shall not be assessed deviations for the Real-time Settlement Interval if its deviation percentage <= 0.10 (10 percent).

$$Deviation\ Percentage = Abs\left[1 - \frac{Actual\ MWh}{Tracking\ Ramp\ Limited\ Desired\ MWh}\right]$$

If the Actual MWh is equal to zero, the deviation percentage is equal to 1 (100 percent).

Generation resource deviations are calculated as the difference between a resource's Real-time Settlement Interval MWh and day-ahead scheduled MWh, rather than Tracking Ramp Limited Desired MWh, when a resource is non-dispatchable for any Real-time Settlement Interval. For purposes of this provision, a resource will be considered non-dispatchable when any of the following conditions occur:

- The generation resource is not dispatchable in the Day-ahead Energy Market and is not dispatchable in the Real-time Energy Market. For purposes of the generation resource deviation calculation, not dispatchable is defined as intervals when the minimum operating limit is equal to the maximum operating limit, or intervals when a generation resource elects to provide a fixed output using the fixed generation parameter, or other not dispatchable processes as defined in the PJM Manuals. All hydro resources are considered non-dispatchable unless operated as a dispatchable resource by the Office of the Interconnection.
- The self-scheduled generation resource is not dispatchable due to a limited dispatchable range. A dispatchable range is considered limited when the following equation is true:
    - Abs(maximum operating limit – minimum operating limit) <= 10% of Abs(minimum operating limit).
- The dispatchable self-scheduled generation resource has a Tracking Ramp Limited Desired MWh <= the minimum operating limit, except when the resource is desired at that level due to a Minimum Generation Emergency declaration or event.
- A generation resource is online and Tracking Ramp Limited Desired MWh is unable to be calculated due to unavailable schedules or offer parameters.

A generation resource shall not be assessed deviations for the Real-time Settlement Interval if its day-ahead deviation percentage is <= 0.05 (5%).

$$Day-ahead\ Deviation\ Percentage = Abs\left[1 - \frac{Actual\ MWh}{Day-ahead\ Scheduled\ MWh}\right]$$

If the Actual MWh is equal to zero, the day-ahead deviation percentage is equal to 1 (100 percent).

A generation resource shall not be assessed deviations in a Real-time Settlement Interval if any of the following conditions occur for that interval:

- The resource is assigned pool-scheduled Regulation.
- The resource is assigned pool-scheduled Real-time Synchronized Reserves as a synchronous condenser.
- The resource is assigned pool-scheduled Real-time Secondary Reserves as a synchronous condenser.
- The resource is assigned pool-scheduled Real-time Non-Synchronized Reserves.

- The resource is assigned Real-time Synchronized Reserves and responded during a Synchronized Reserve Event.
- Flexible Resources that are committed in the Day-ahead Energy Market and not committed by the Office of the Interconnection in the Real-time Energy Market and the resource is offline.
- The resource is manually dispatched by the Office of the Interconnection and the manual instruction is not reflected in the Tracking Ramp Limited Desired MWh.

Deviations of generation resources with multiple units located at a single bus shall be netted for each Real-time Settlements Interval as described in Tariff, Attachment K-Appendix, section 3.2.3(h)(i).

If a resource has an hourly average ~~sum~~ of the absolute value of generator deviations ~~for an hour~~ that is less than 5 MWh, then the resource shall not be assessed ~~balancing Operating Reserve~~ deviations for each Real-time Settlement Interval in that hour. This calculation shall be done after netting is applied, where applicable.

For the purpose of this section 3.2.3(o), a generation resource is considered to be following dispatch if it is not assessed deviations or has a deviation equal to zero in a Real-time Settlement Interval, as determined above and prior to any netting pursuant to section 3.2.3(h)(i) or for hourly averages pursuant to this section

(o-1) Dispatchable Economic Load Response Participant resources that follow dispatch shall not be assessed ~~balancing Operating Reserve~~ deviations. Economic load reduction resources that do not follow dispatch shall be assessed ~~balancing Operating Reserve~~ deviations as described in this subsection and as further specified in the PJM Manuals.

The Desired MW quantity for such resources for each hour shall be the hourly integrated MW quantity to which the load reduction resource was dispatched for each hour (where the hourly integrated value is the average of the dispatched values as determined by the Office of the Interconnection for the resource for each hour).

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no ~~balancing Operating Reserve~~ deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the ~~balancing Operating Reserve~~ deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual reduction quantity) and charged as defined in Tariff, Attachment K-Appendix, section 3.3A. For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined in Tariff, Attachment K-Appendix, section 3.3A. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall ~~allocate the charges assessed~~apply any balancing Energy Make Whole credits determined pursuant to Tariff, Attachment K-Appendix, section 3.2.3(e-2~~h~~), except those associated with the scheduling of units for Black Start S~~s~~ervice or testing of Black Start Service ~~U~~units as provided in Tariff, Schedule 6A, to ~~real-time~~ deviations ~~from day-ahead schedules~~ determined pursuant to section 3.2.3(h) or real-time load ~~share~~ plus exports depending on whether the underlying balancing ~~Operating Reserve~~Energy Make Whole credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day. ~~Allocation to real-time load share under this subsection (p) shall not apply to Direct Charging Energy. If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, section 1.11.6, the Office of the Interconnection shall allocate the charges to the ratio share of real-time load plus export transactions.~~

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Energy Make Whole credits ~~Operating Reserve charges~~ shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Energy Make Whole credits, identified as reliability analysis credits for deviations, ~~Operating Reserve charges~~ shall be allocated to ~~real-time~~ deviations determined pursuant to Tariff, Attachment K-Appendix, section 3.2.3(h)~~from day-ahead schedules~~.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Energy Make Whole credits, identified as reliability analysis credits for reliability, ~~Operating Reserve charges~~ shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Energy Make Whole credits shall be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(p)(i)(A) and 3.2.3(p)(i)(B) hereof~~Operating Reserve charges shall be allocated pursuant to (A) or (B) above~~.

(ii) For resources scheduled during an Operating Day, the associated balancing Energy Make Whole credits ~~Operating Reserve charges~~ shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Energy Make Whole credits, identified as real-time credits for reliability, ~~Operating Reserve charges~~ shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, ~~charges will be assessed~~credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceeds the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the ~~charges~~ credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (real-time credits for reliability or real-time credits for deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Tariff, Attachment K-Appendix, section 3.2.3(~~ph~~)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Energy Make Whole credits, identified as real-time credits for deviations, ~~Operating Reserve charges~~ shall be allocated ~~according~~ to ~~real-time~~ deviations ~~from day-ahead schedules~~ determined pursuant to Tariff, Attachment K-Appendix, section 3.2.3(h).

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in Tariff, Attachment K-Appendix, sections 3.2.3(p)(i) and (p)(ii).

The costs associated with scheduling of units for Black Start Service or testing of Black Start Service units shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zonal load or non-Zonal load, as determined in accordance with the formulas contained in Tariff, Schedule 6A.

(q) (i) Balancing Energy Make Whole credits for reliability or deviations as determined in Tariff, Attachment K-Appendix, section 3.2.3(p) shall be assigned to the Eastern or Western region if the credit paid to the generator is due to transmission constraints that occur on transmission system capacity equal to or less than 345kv. Balancing Energy Make Whole credits for reliability or deviations not assigned to the Eastern or Western region shall be assigned to the RTO region.~~The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region.~~ For the purposes of this section, the Western ~~R~~region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, DEOK, EKPC, OVEC transmission Zones, and the Eastern ~~R~~region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones. ~~The regional~~

~~balancing Operating Reserve rates shall be determined in accordance with the following provisions:~~

(ii) The total balancing Energy Make Whole credits for reliability in each region shall be allocated as charges to each Market Participant's pro rata share of real-time load plus export transactions in such region. For purposes of this Tariff, Attachment K-Appendix, section 3.2.3(q), a Market Participant's real-time load plus export transactions shall be equal to the daily total of (i) real-time deliveries of energy to load in the relevant region ((a) net of operating Behind The Meter Generation, but not to be less than zero; and (b) excluding Direct Charging Energy), served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) real-time deliveries of energy sales from within the PJM Region to load outside the PJM Region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Tariff, Attachment K-Appendix, section 1.12.

(iii) The total balancing Energy Make Whole credits for deviations in the Eastern region and the Western region shall be allocated as charges to each Market Participant's pro rata share of the daily total of hourly deviations in the relevant region as determined pursuant to Tariff, Attachment K-Appendix, section 3.2.3(h). The total balancing Energy Make Whole credits for deviations in the RTO region plus the total credits as determined in Tariff, Attachment K-Appendix, section 3.2.3(g) shall be allocated as charges to each Market Participant's pro rata share of the daily total of hourly deviations in the RTO region as determined pursuant to Tariff, Attachment K-Appendix, section 3.2.3(h). If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.11.6, the Office of the Interconnection shall allocate deviation charges to the ratio share of real-time load plus export transactions pursuant to Tariff, Attachment K-Appendix, section 3.2.3(q)(ii).

(q-1) (i) ~~The r~~Regional balancing ~~Operating Reserve~~uplift rates shall be determined in accordance with the following provisions:

The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western r~~R~~egions. Regional adder rates for reliability shall be equal to the total balancing ~~Operating Reserve~~Energy Make Whole credits ~~paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into~~for reliability in the region divided by the total real-time load plus export transactions in the relevant region in accordance with Tariff, Attachment K-Appendix, section 3.2.3(q)(ii)~~and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively~~. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with Tariff,

Attachment K-Appendix, section 3.2.3(p). ~~Allocation to real-time load share under this subsection (q)(i) shall not apply to Direct Charging Energy.~~

Regional adder rates for deviations shall be equal to the total balancing Energy Make Whole credits for deviations in the region divided by the daily total of hourly deviations in the relevant region in accordance with Tariff, Attachment K-Appendix, section 3.2.3(q)(iii).

(ii) The Office of the Interconnection shall calculate RTO balancing ~~Operating Reserve~~uplift rates. RTO balancing ~~Operating Reserve~~uplift rates for reliability shall be equal to the total balancing ~~Operating Reserve~~Energy Make Whole credits for reliability in the RTO region divided by the total real-time load plus export transactions in the RTO region in accordance with section (q)(ii). RTO balancing uplift rates for deviations shall be equal to the total balancing Energy Make Whole credits for deviations in the RTO region plus the total credits as determined in Tariff, Attachment K-Appendix, section 3.2.3(g) divided by the daily total of hourly deviations in the RTO region as determined pursuant to Tariff, Attachment K-Appendix, section 3.2.3(h). ~~except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Tariff, Schedule 6A, in excess of the regional adder rates calculated pursuant to Tariff, Attachment K-Appendix, section 3.2.3(q)(i). The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively.~~ Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Tariff, Attachment K-Appendix, section 3.2.3(p). ~~Allocation to real-time load share under this subsection (q)(ii) shall not apply to Direct Charging Energy.~~

(iii) Reliability and deviation regional balancing ~~Operating Reserve~~uplift rates shall be determined by summing the relevant RTO balancing ~~Operating Reserve~~Energy Make Whole rates and regional adder rates.

~~(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.~~

(r) Market Sellers that incur incremental operating costs for a generation resource that are either greater than $1,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Operating Agreement, Schedule 2 and PJM Manual 15, but are not verified at the time of dispatch of the resource under Tariff, Attachment K-Appendix, section 6.4.3, or greater than $2,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Operating Agreement, Schedule 2, and PJM Manual 15, will be eligible to receive credit for ~~Operating Reserves~~Energy Make Whole upon review of the Market Monitoring Unit and the Office of the Interconnection, and approval of the Office of the Interconnection. Market Sellers must submit to the Office of the Interconnection and the Market Monitoring Unit all relevant documentation demonstrating the calculation of costs greater than

$2,000/MWh, and costs greater than $1,000/MWh which were not verified at the time of dispatch of the resource under Tariff, Attachment K-Appendix, section 6.4.3. The Office of the Interconnection must approve any ~~Operating Reserve~~Energy Make Whole credits paid to a Market Seller under this subsection (r).

3.2.3A Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant's hourly Synchronized Reserve Obligation shall be adjusted by any Synchronized Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Synchronized Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Synchronized Reserve as defined in sections 3.2.3A(b)(i) and (ii) below.

(b) A resource supplying Synchronized Reserve at the direction of the Office of the Interconnection shall be credited as follows:

i) Credits for Synchronized Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Synchronized Reserve by the Office of the Interconnection or self-scheduled in the Day-ahead Synchronized Reserve Market shall be equal to the product of the Day-ahead Synchronized Reserve Market Clearing Price multiplied by the megawatt amount of Synchronized Reserve such resource is assigned to provide.

ii) Credits for Synchronized Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Synchronized Reserve by the Office of the Interconnection or self-scheduled in the Real-time Synchronized Reserve Market shall be determined for each operating hour based on the sum of their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$$\sum_i ((A - B) * C)$$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Synchronized Reserve from that resource assigned by the Office of the Interconnection or self-scheduled in the Real-time Synchronized Reserve Market. The megawatt value is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval where there is not a Synchronized Reserve event;

B = For each Real-time Settlement Interval, the megawatts of Synchronized Reserve from that resource assigned by the Office of the Interconnection or self-scheduled in the Day-ahead Synchronized Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Synchronized Reserve Market Clearing Price.

If a Synchronized Reserve Event is initiated by the Office of the Interconnection and the Economic Load Response Participant resource reduced its load in response to the event, the resource shall be eligible to receive a credit for the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

iii) Pool-scheduled resources shall be credited a Synchronized Reserve lost opportunity cost credit, where positive, as described in subsection (f)(iv) below.

(c) [Reserved for future use]

(d) Synchronized Reserve Market Clearing Prices

(i) For the Day-ahead Synchronized Reserve Market, the Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Synchronized Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for Synchronized Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Synchronized Reserve offer prices and opportunity costs and the Operating Reserve Demand Curve for Synchronized Reserve for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Synchronized Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute and (B) the price of serving the next increment of demand for Primary Reserve and 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.10.8(d), Day-ahead Synchronized Reserve Market Clearing Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and Day-ahead Synchronized Reserve Market Clearing

Price of zero dollars per megawatt-hour and all settlements will be based on the Real-time Synchronized Reserve market quantities and prices as determined pursuant to subsection (d)(ii) hereof.

(ii) For the Real-time Synchronized Reserve Market, the Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for Synchronized Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Synchronized Reserve offer prices and opportunity costs and the Operating Reserve Demand Curve for Synchronized Reserve for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Synchronized Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute and (B) the price of serving the next increment of demand for Primary Reserve and 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, and the Office of the Interconnection is not assigning Synchronized Reserves, then the Synchronized Reserve Market Clearing Price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, where the real-time Market Suspension is less than or equal to six (6) consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Synchronized Reserves, then the Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Synchronized Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than six (6) consecutive hours but less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating Days, and there are cleared Day-ahead Synchronized Reserve Market Clearing Prices for the affected Operating Day, then the Real-time Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the Day-ahead Synchronized Reserve Market Clearing Prices for each corresponding hour. If no such Day-ahead Synchronized Reserve Market Clearing Prices exist, then the Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Synchronized Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than twenty-four (24) consecutive hours, and the Office of the Interconnection is assigning Synchronized Reserves, the Office of the Interconnection will set the Synchronized Reserve Market Clearing Price to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period. Resources will be compensated for lost opportunity cost per subsection (f) hereof using the energy price as determined in Operating Agreement, Schedule 1, section 2.5.2.iii. The opportunity cost shall be zero for all resources self-scheduled to provide Synchronized Reserve, synchronous condensers and Economic Load Response Participant resources.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Synchronized Reserve Market Clearing Price shall be the sum of the Reserve Penalty Factors for the Primary Reserve Requirement, and the Synchronized Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

(iii) The Reserve Penalty Factor for the Minimum Synchronized Reserve Requirement shall be $2,000/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $2,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Reserve Penalty Factor on the Operating Reserve Demand Curves for Synchronized Reserve are warranted for subsequent Delivery Year(s).

(e) (i) For determining the Synchronized Reserve Market Clearing Price in each hour of the Day-ahead Synchronized Reserve Market, the estimated resource-specific opportunity cost for a generation resource or Economic Load Response Participant resource shall be the difference between the Locational Marginal Price at the generation or Economic Load Response Participant resource bus and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) or offer price to reduce energy from the Economic Load Response Participant resource in the PJM Interchange Energy Market when the Locational Marginal Price at the generation or Economic Load Participant resource bus is greater than the offer price for energy from the generation resource or the offer price to reduce energy from the Economic Load Response Participant resource.

However, opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve and for synchronous condensers and for Economic Load Response Participant resources that do not receive a day-ahead commitment to provide energy in the same operating hour in which such resource is committed to provide Synchronized Reserve.

(ii) For determining the Synchronized Reserve Market Clearing Price for each Real-time Settlement Interval in the Real-time Synchronized Reserve Market, the estimated unit-specific opportunity cost for a generation resource that is not a hydroelectric resource shall be the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

For hydroelectric resources, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions, as defined in the PJM Manuals, and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

The opportunity costs shall be zero for all resources self-scheduled to provide Synchronized Reserve, synchronous condensers and Economic Load Response Participant resources.

(f) (i) In determining the credit under subsection (b) to a generation resource, except a generation resource that is operating as a synchronous condenser, selected to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market, or an Economic Load Response Participant resource that is selected to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market for the same operating hour in which such resource receives a day-ahead commitment to provide energy, the opportunity cost of a resource shall be determined for each operating hour that the Office of the Interconnection requires a resource to provide Synchronized Reserve and shall be in accordance with the following equation:

(A x B) – C

Where:

A = The Day-ahead Locational Marginal Price at the generation bus of the generation resource or the applicable pricing point for the Economic Load Response Participant resource;

B = The deviation of the resource's energy output or load reduction necessary to supply a Day-ahead Synchronized Reserve assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load; and

C = The Day-ahead Energy market offer integrated under the applicable energy offer curve for the resource's energy output or load reduction necessary to provide a Day-ahead Synchronized Reserve Market assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load.

For a generation resource that is operating as a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [Condense Energy Use multiplied by A] plus [the applicable Condense Startup Cost divided by the number of hours the resource is assigned Synchronized Reserve].

(ii) In determining the credit under subsection (b) to a generation resource, except a generation resource that is operating as a synchronous condenser, selected to provide Synchronized Reserve in the Real-time Synchronized Reserve Market in excess of the resource's Day-ahead Synchronized Reserve Market assignment and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of that generation resource shall be determined for each Real-time Settlement Interval that the Office of the Interconnection requires that generation resource to provide Synchronized Reserve and shall be in accordance with the following equation:

(A x B) - C

Where:

A = The Real-time Locational Marginal Price at the generation bus of the generation resource;

B = The deviation of the generation resource's output necessary to supply Synchronized Reserve in real-time, reduced by the amount of Synchronized Reserve the resource failed to respond during a Synchronized Reserve Event during the Operating Day, in excess of its Day-ahead Synchronized Reserve Market assignment and follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy; and

C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Synchronized Reserve in real-time from the lesser of the generation resource's output necessary to provide a Day-ahead Synchronized Reserve Market assignment or follow the Office of the

Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [additional Condense Energy Use in excess of day-ahead Condense Energy Use in real-time multiplied by A] plus [any applicable Condense Startup Cost due to additional Condense Startup Cost in real-time in excess of day-ahead Condense Startup Cost allocated to each Real-time Settlement Interval as described in PJM Manuals].

For hydroelectric resources, the unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the real-time Locational Marginal Price at that generation bus multiplied by the additional megawatts assigned to supply Synchronized Reserve in real-time in excess of its Day-ahead Synchronized Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average real-time Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating multiplied by the additional megawatts assigned to supply the hourly Synchronized Reserve in real-time in excess of its Day-ahead Synchronized Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

(iii) For each Real-time Settlement Interval, a Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in the resource's real-time reserve MW from a day-ahead market assignment in more than one market for that Real-time Settlement Interval, the total Market Revenue Neutrality Offset is allocated to the Synchronized Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Synchronized Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Synchronized Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Synchronized Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Synchronized Reserve assignment decreases due to the resource being self-scheduled to provide energy or Regulation;

(B) A resource reduces its flexibility in real-time such that the resource no longer qualifies to provide Synchronized Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time;

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above; or

(F) A resource increases its Synchronized Reserve offer price in the Real-time Synchronized Reserve Market from its offer price in the Day-ahead Synchronized Reserve Market.

(iv) A Synchronized Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

(A + B + C + D) – (E + F + G + H)

Where:

A = day-ahead Synchronized Reserve offer price times the Synchronized Reserve MW assignment;

B = real-time Synchronized Reserve offer price times the Synchronized Reserve MW assigned in real-time in excess of the Synchronized Reserve MW assigned day-ahead, where the Synchronized Reserve MW assigned is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval where there is not a Synchronized Reserve event;

C = day-ahead opportunity cost as determined in subsection (f)(i) above;

D = real-time opportunity cost as determined in subsection (f)(ii) above;

E = day-ahead clearing price credits as determined in subsection (b)(i) above;

F = real-time clearing price credits as determined in subsection (b)(ii) above less any applicable charges for failure to respond to a Synchronized Reserve Event as determined in subsection (j) below;

G = the applicable Market Revenue Neutrality Offset as determined in subsection (f)(iii) above; and

H = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A(f)(iii) above if not eligible for Market Revenue Neutrality Offset.

(v) The opportunity costs for an Economic Load Response Participant resource assigned Synchronized Reserve in real-time or any resource self-scheduled for Synchronized Reserves shall be zero.

(g) [Reserved for future use]

(h) For each operating hour, the sum of the Synchronized Reserve lost opportunity cost credits credited in accordance with subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Synchronized Reserve Obligation in proportion to its real-time purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) [Reserved for future use]

(j) In the event a generation resource or Economic Load Response Participant resource that either has been assigned by the Office of the Interconnection or self-scheduled to provide Synchronized Reserve in real-time fails to provide the amount of Synchronized Reserve it was directed to deploy in response to a Synchronized Reserve Event, the resource will be charged at the Real-time Synchronized Reserve Market Clearing Price for the real-time Synchronized Reserve the resource was directed to deploy, in excess of the amount that actually responded for all Real-time Settlement Intervals the resource was assigned or self-scheduled Synchronized Reserve real-time. For each Real-time Settlement Interval where there is not a Synchronized Reserve Event, the megawatts that will be charged shall be the lesser of the amount of the shortfall of Synchronized Reserve, measured in megawatts, or the real-time Synchronized Reserve assignment, which is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements for the resource on the Operating Day during which the event occurred. The determination of the amount of Synchronized Reserve credited to a resource shall be on an individual resource basis, not on an aggregate basis.

The resource shall refund payments received for Synchronized Reserve it failed to provide. For purposes of determining the amount of the payments to be refunded by a Market Participant, the Office of the Interconnection shall calculate the shortfall of Synchronized Reserve on an individual resource basis unless the Market Participant had multiple resources that were assigned or self-scheduled to provide Synchronized Reserve, in which case the shortfall will be determined on an aggregate basis. For performance determined on an aggregate basis, the response of any resource that was assigned or self-scheduled for Synchronized Reserve and provided more Synchronized Reserve than it was directed to deploy will be used to offset the performance of other resources that provided less assigned or self-scheduled Synchronized Reserve than they were directed to deploy during a Synchronized Reserve Event, as calculated in the PJM Manuals. The determination of a Market Participant's aggregate response shall not be

taken into consideration in the determination of the amount of Synchronized Reserve credited to each individual resource.

The amount refunded shall be determined by multiplying the retroactive penalty megawatts by the Real-time Synchronized Reserve Market Clearing Price for all intervals the resource was assigned or self-scheduled to provide Synchronized Reserve for a period of time immediately preceding the Synchronized Reserve Event equal to the lesser of the average number of days between Synchronized Reserve Events, or the number of days since the resource last failed to provide the amount of Synchronized Reserve it was directed to deploy in response to a Synchronized Reserve Event. The retroactive penalty megawatts for each interval shall be the lesser of the amount of the shortfall of Synchronized Reserve, measured in megawatts, and the real-time Synchronized Reserve assignment for each interval, which is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements for the resource. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following January 1. The refunded charges shall be allocated as credits to Market Participants based on its pro rata share of the Synchronized Reserve Obligation megawatts in the hour(s) of the Synchronized Reserve Event for the Reserve Sub-zone or Reserve Zone, except that Market Participants that incur a refund obligation and also have an applicable Synchronized Reserve Obligation during the hour(s) of the Synchronized Reserve Event shall not be included in the allocation of such refund credits. If the event spans multiple hours, the refund credits will be prorated hourly based on the duration of the event within each clock hour.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or an Economic Load Response Participant resource, except for Batch Load Economic Load Response Participant Resources covered by section 3.2.3A(l) below, is the difference between the generation resource's output or the Economic Load Response Participant resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Economic Load Response Participant resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Economic Load Response Participant resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or an Economic Load Response Participant resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Economic Load Response Participant resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to an Economic Load Response Participant resource will be reduced by the amount the megawatt consumption of the Economic Load Response Participant resource exceeds the level achieved

after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Economic Load Response Participant Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load Economic Load Response Participant Resource's consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Economic Load Response Participant Resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Economic Load Response Participant Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant's hourly Non-Synchronized Reserve Obligation shall be adjusted by any Non-Synchronized Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Non-Synchronized Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Non-Synchronized Reserve as defined in sections 3.2.3A.001(b)(i) and (ii) below.

(b) Resources assigned to provide Non-Synchronized Reserve at the direction of the Office of the Interconnection shall be credited as follows:

(i) Credits for Non-Synchronized Reserve provided by generation resources assigned to provide Non-Synchronized Reserve by the Office of the Interconnection in the Day-ahead Non-Synchronized Reserve Market shall be equal to the product of the Day-ahead Non-Synchronized Market Clearing Price multiplied by the megawatt amount of Non-Synchronized Reserve such resource is assigned to provide.

(ii) Credits for Non-Synchronized Reserve provided by generation resources assigned to provide Non-Synchronized Reserve by the Office of the Interconnection in the Real-time Non-Synchronized Reserve Market shall be determined for each operating hour based on the sum on their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$\sum_i ((A - B) * C)$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Non-Synchronized Reserve from that resource assigned by the Office of the Interconnection in the Real-time Non-Synchronized Reserve Market;

B = For each Real-time Settlement Interval, the megawatts of Non-Synchronized Reserve from that resource assigned by the Office of the Interconnection in the Day-ahead Non-Synchronized Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Non-Synchronized Reserve Market Clearing Price.

(iii) Pool-scheduled generation resources assigned to provide Non-Synchronized Reserve in the Day-ahead Non-Synchronized Reserve Market shall be credited a Non-Synchronized Reserve lost opportunity cost credit, where positive, as determined in accordance with subsection (d)(iii) below, to recover any net monetary loss to the Market Seller of such resource associated with the purchase of Non-Synchronized Reserve in the Real-time Non-Synchronized Reserve Market as a result of following the dispatch direction of the Office of the Interconnection.

(c) Non-Synchronized Reserve Market Clearing Prices

(i) For the Day-ahead Non-Synchronized Reserve Market, the Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Non-Synchronized Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for Primary Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Non-Synchronized Reserve offer prices and the Operating Reserve Demand Curve for Primary Reserve for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Primary Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute and (B) the price of serving the next increment of demand for 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.10.8(d), Day-ahead Non-Synchronized Reserve Market Clearing Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a

scheduled megawatt quantity and Day-ahead Non-Synchronized Reserve Market Clearing Price of zero dollars per megawatt-hour and all settlements will be based on the Real-time Non-Synchronized Reserve market quantities and prices as determined pursuant to subsection (c)(ii) hereof.

(ii) For the Real-time Non-Synchronized Reserve Market, the Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for Primary Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Non-Synchronized Reserve offer prices and the Operating Reserve Demand Curve for Primary Reserve for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Primary Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute and (B) the price of serving the next increment of demand for 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, and the Office of the Interconnection is not assigning Non-Synchronized Reserves, then the Non-Synchronized Reserve Clearing Price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, where the real-time Market Suspension is less than or equal to six (6) consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Non-Synchronized Reserves, then the Non-Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Non-Synchronized Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than six (6) consecutive hours but less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating Days, and there are cleared Day-ahead Non-Synchronized Reserve Market Clearing Prices for the affected Operating Day, then the Real-time Non-Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the Day-ahead Non-Synchronized Reserve Market Clearing Prices for each corresponding hour. If no such Day-ahead Non-Synchronized Reserve Market Clearing Prices exist, then the Non-Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Non-Synchronized Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than twenty-four (24) consecutive hours, the

Non-Synchronized Reserve Market Clearing Price will be set to zero dollars per megawatt-hour regardless of whether the Office of the Interconnection is assigning Non-Synchronized Reserves.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Non-Synchronized Reserve Market Clearing Price shall be the product of 1.5 multiplied by the Reserve Penalty Factor for the Primary Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

(iii) The Reserve Penalty Factor for the Minimum Primary Reserve Requirement shall be $2,000/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $2,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Reserve Penalty Factor on the Operating Reserve Demand Curves for Primary Reserve are warranted for subsequent Delivery Year(s).

(d) (i) For determining the Non-Synchronized Reserve clearing price for each hour in the Day-ahead Non-Synchronized Reserve Market and for each Real-time Settlement Interval in the Real-time Non-Synchronized Reserve Market, including during a declaration of a Market Suspension, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves will be zero.

(ii) For each Real-time Settlement Interval, a total Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in real-time reserve MW from a day-ahead market assignment in more than one market for that Real-time Settlement Interval, the total Market Revenue Neutrality Offset is allocated to the Non-Synchronized Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Non-Synchronized Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Non-Synchronized Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Non-Synchronized Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Non-Synchronized Reserve assignment decreases due to the resource being self-scheduled to provide energy, Synchronized Reserve, or Regulation;

(B) A resource reduces flexibility in real-time such that the resource no longer qualifies to provide Non-Synchronized Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time; or

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above.

(iii) A Non-Synchronized Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

(zero) – (A + B + C + D)

Where:

A = day-ahead clearing price credits as determined in subsection (b)(i) above;

B = real-time clearing price credits as determined in subsection (b)(ii) above;

C = the applicable Market Revenue Neutrality Offset as determined in subsection (d)(ii) above; and

D = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A.001(d)(ii) above if not eligible for Market Revenue Neutrality Offset.

(e) [Reserved for future use]

(f) For each operating hour, the sum of the Non-Synchronized Reserve lost opportunity cost credits credited in subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation in proportion to its real-time purchases of Non-Synchronized Reserve in megawatt-hours during that hour.

(g) The magnitude of response to a Non-Synchronized Reserve Event by a generation resource is the difference between the generation resource's output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output at the start of the event is defined as the lowest telemetered generator resource output between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output 10 minutes after the start of the event is defined as the greatest generator resource output achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will

be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(h) In the event a generation resource that has been assigned by the Office of the Interconnection to provide Non-Synchronized Reserve fails to provide the assigned amount of Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the contiguous Real-time Settlement Interval the resource was assigned Non-Synchronized Reserve during which the event occurred.

3.2.3A.01 Secondary Reserve.

(a) Each Market Participant that is a Load Serving Entity shall have an obligation for hourly Secondary Reserve equal to its pro rata share of Secondary Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Secondary Reserve Obligation"). A Market Participant's hourly Secondary Reserve Obligation shall be adjusted by any Secondary Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Secondary Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Secondary Reserve as defined in sections 3.2.3A.01(b)(i) and (ii) below.

(b) Resources assigned to provide Secondary Reserve at the direction of the Office of the Interconnection shall be credited as follows:

(i) Credits for Secondary Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Secondary Reserve by the Office of the Interconnection in the Day-ahead Secondary Reserve Market shall be equal to the product of the Day-ahead Secondary Reserve Market Clearing Price multiplied by the megawatt amount of Secondary Reserve such resource is scheduled to provide.

(ii) Credits for Secondary Reserve provided by generation resources and Economic Load Response Participant resources scheduled to provide Secondary Reserve by the Office of the Interconnection in the Real-time Secondary Reserve Market shall be determined for each operating hour based on the sum of their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$\sum_i ((A - B) * C)$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Secondary Reserve from that resource assigned by the Office of the Interconnection in the Real-time Secondary Reserve Market. The megawatt value is capped at the lesser of the Economic Maximum or Secondary Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval minus the Real-time Synchronized Reserve assignment;

B = For each Real-time Settlement Interval, the megawatts of Secondary Reserve from that resource scheduled by the Office of the Interconnection in the Day-ahead Secondary Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Secondary Reserve Market Clearing Price.

(iii) Pool-scheduled resources and Economic Load Response Participant resources shall be credited a Secondary Reserve lost opportunity cost credit, where positive, as described in subsection (f)(iv) below.

(c) [Reserved for future use]

(d) Secondary Reserve Market Clearing Prices

(i) For the Day-ahead Secondary Reserve Market, the Secondary Reserve Market Clearing Price shall be determined for each Reserve Zone and, as applicable, Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Secondary Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for 30-minute Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Secondary Reserve offer prices and opportunity costs and the Operating Reserve Demand Curve for 30-minute Reserve for that Reserve Zone or Reserve Sub-zone, plus the price of serving the next increment of demand for 30-minute Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.10.8(d), Day-ahead Secondary Reserve Market Clearing Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and Day-ahead Secondary Reserve Market Clearing Price of zero dollars per megawatt-hour and all settlements will be based on the Real-time Secondary Reserve market quantities and prices as determined pursuant to subsection (d)(ii) hereof.

(ii) For the Real-time Secondary Reserve Market, the Secondary Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each Real-time Settlement Interval of the

Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for 30-minute Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Secondary Reserve offer prices and opportunity costs and the Operating Reserve Demand Curve for 30-minute Reserve for that Reserve Zone or Reserve Sub-zone plus the price of serving the next increment of demand for 30-minute Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, and the Office of the Interconnection is not assigning Secondary Reserves, then the Secondary Reserve Clearing Price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, where the real-time Market Suspension is less than or equal to six (6) consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Secondary Reserves, then the Secondary Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Secondary Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than six (6) consecutive hours but less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating Days, and there are cleared Day-ahead Secondary Reserve Market Clearing Prices for the affected Operating Day, then the Real-time Secondary Reserve Market Clearing Prices associated with such Market Suspension shall be the Day-ahead Secondary Reserve Market Clearing Prices for each corresponding hour. If no such Day-ahead Secondary Reserve Market Clearing Prices exist, then the Secondary Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Secondary Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than twenty-four (24) consecutive hours, and the Office of the Interconnection is assigning Secondary Reserves, the Secondary Reserve Market Clearing Price will be set to zero dollars per megawatt-hour. Resources will be compensated for lost opportunity cost per subsection (f) hereof using the energy price as determined in Operating Agreement, Schedule 1, section 2.5.2.iii.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Secondary Reserve Market Clearing Price for a given Reserve Zone or Sub-zone shall be the Reserve Penalty Factor for the 30-minute Reserve Requirements for that Reserve Zone or Reserve Sub-zone.

(iii) The Reserve Penalty Factor for the Minimum 30-minute Reserve Requirement shall be $2000/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $2,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Reserve Penalty Factor on the Operating Reserve Demand Curves for 30-minute Reserve are warranted for subsequent Delivery Year(s).

(e) (i) For determining the Secondary Reserve Market Clearing Price for each hour in the Day-ahead Secondary Reserve Market, the estimated resource-specific opportunity cost for a generation resource or Economic Load Response Participant resources shall be the difference between the Locational Marginal Price at the generation or Economic Load Response Participant resource bus and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) or offer price to reduce energy from the Economic Load Response Participant resource in the PJM Interchange Energy Market when the Locational Marginal Price at the Economic Load Response Participant resource bus is greater than the offer price for energy from the generation resource or the offer price to reduce energy from the Economic Load Response Participant resource.

However, opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve, and for synchronous condensers and for Economic Load Response Participant resources that do not receive a day-ahead commitment to provide energy in the same operating hour in which such resource is committed to provide Secondary Reserve.

(ii) For determining the Secondary Reserve Market Clearing Price for each Real-time Settlement Interval in the Real-time Secondary Reserve Market, the estimated unit-specific opportunity cost for a generation resource that is not a hydroelectric resource shall be the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

For hydroelectric resources, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference

between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

However, the opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve, and for synchronous condensers and Economic Load Response Participant resources.

(f) (i) In determining the credit under subsection (b) to a generation resource, except a generation resource that is a synchronous condenser, selected to provide Secondary Reserve in the Day-ahead Secondary Reserve Market or an Economic Load Response Participant resource that is selected to provide Secondary Reserve in the Day-ahead Secondary Reserve Market in the same operating hour in which such resource receives a day-ahead commitment to provide energy, the opportunity cost of a resource shall be determined for each operating hour that the Office of the Interconnection requires a resource to provide Secondary Reserve and shall be in accordance with the following equation:

(A x B) – C

Where:

A = The Day-ahead Locational Marginal Price at the generation bus of the generation resource or the applicable pricing point for the Economic Load Response Participant resource;

B= The deviation of the resource's energy output or load reduction necessary to supply a Day-ahead Secondary Reserve assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load less any Day-ahead Synchronized Reserve Market assignment; and

C = The Day-ahead Energy Market offer integrated under the applicable energy offer curve for the resource's energy output or load reduction necessary to provide a Day-ahead Secondary Reserve Market assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load less any Day-ahead Synchronized Reserve Market assignment.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [Condense Energy Use

multiplied by A] plus [the applicable Condense Startup Cost divided by the number of hours the resource is assigned Secondary Reserve].

(ii) In determining the credit under subsection (b) to a generation resource, except a generation that is a synchronous condenser, selected to provide Secondary Reserve in the Real-time Secondary Reserve Market in excess of the resource's Day-ahead Secondary Reserve Market assignment and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of that generation resource shall be determined for each Real-time Settlement Interval that the Office of the Interconnection requires that generation resource to provide Secondary Reserve and shall be in accordance with the following equation:

(A x B) – C

Where:

A = The Real-time Locational Marginal Price at the generation bus of the generation resource;

B= The deviation of the generation resource's output necessary to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment and follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy less any Real-time Synchronized Reserve Market assignment; and

C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Secondary Reserve in real-time from the lesser of the generation resource's output necessary to provide a Day-ahead Secondary Reserve Market assignment or follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy less any Real-time Synchronized Reserve Market assignment.

For hydroelectric resources, the unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the real-time Locational Marginal Price at that generation bus multiplied by the additional megawatts assigned to supply Synchronized Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average real-time Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during

which all available units at the hydroelectric resource were operating multiplied by the additional megawatts assigned to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: additional Condense Energy Use in excess of day-ahead Condense Energy Use multiplied by A plus [any applicable Condense Startup Cost due to additional Condense Startup Cost in real-time in excess of day-ahead Condense Startup Cost allocated to each Real-time Settlement Interval as described in PJM Manuals]. If the generation resource is operating as a synchronous condenser and also has a Real-time Synchronized Reserve assignment, resource's unit-specific opportunity cost in the Secondary Reserve Market shall be zero.

(iii) For each Real-time Settlement Interval, a total Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in real-time reserve MW from a day-ahead market assignment in more than one market for that real-time settlement interval, the total Market Revenue Neutrality Offset is allocated to the Secondary Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Secondary Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Secondary Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Secondary Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Secondary Reserve assignment decreases due to the resource being self-scheduled to provide energy, Synchronized Reserve, or Regulation;

(B) A resource reduces flexibility in real-time such that the resource no longer qualifies to provide Secondary Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time;

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above; or

(F) A resource that fails to come online and reach Economic Minimum output within 30 minutes as described in section 3.2.3A.01(h)(i) below.

(iv) A Secondary Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

(A + B) – (C + D + E + F)

Where:

A = day-ahead opportunity cost as determined in subsection (f)(i) above;

B = real-time opportunity cost as determined in subsection (f)(ii) above;

C = day-ahead clearing price credits as determined in subsection (b)(i) above;

D = real-time clearing price credits as determined subsection (b)(ii) above;

E = the applicable Market Revenue Neutrality Offset as determined in subsection (f)(iii) above; and

F = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A.01(f)(iii) above if not eligible for Market Revenue Neutrality Offset.

(v) The opportunity costs for Economic Load Response Participant resources and generation resources not synchronized to the grid shall be zero, except that Economic Load Response Participant resources may have a day-ahead opportunity cost, as determined in subsection (f)(i) above.

(g) For each operating hour, the sum of the Secondary Reserve lost opportunity cost credits credited in accordance with subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Secondary Reserve Obligation in proportion to its real-time purchases of Secondary Reserve in megawatt-hours during that hour.

(h) (i) In the event an offline generation resource has been assigned by the Office of the Interconnection to provide Secondary Reserve in real-time and is subsequently dispatched by the Office of the Interconnection to supply energy during that Operating Day and the resource qualifies as a Secondary Reserve resource at the time it is dispatched to provide energy, the Office of the Interconnection will assess the resource's performance as follows:

For each generation resource that fails to come online and reach Economic Minimum output within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for

that interval and for all prior intervals in which the resource was assigned to provide Secondary Reserve in the Real-time Secondary Reserve Market starting at the later of (A) the last interval the resource was online or (B) the beginning of that Operating Day and continuing up to the interval the resource failed to come online. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time not being paid for the assigned MW.

(ii) In the event an Economic Load Response Participant resource has been assigned by the Office of the Interconnection to provide Secondary Reserve in real-time and is subsequently dispatched to supply the Secondary Reserve assignment as a load reduction, the Office of the Interconnection will assess the resource's performance as follows:

For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between 29 and 31 minutes after the issuance of a dispatch instruction from the Office of the Interconnection.

For each Economic Load Response Participant resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described above, within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval, and for all prior intervals in which the resource was assigned to provide Secondary Reserve in the Real-time Secondary Reserve Market between such non-performance event starting at the later of (A) the last interval the resource reduced load at the instruction of the Office of the Interconnection or (B) the beginning of that Operating Day, and for all subsequent intervals through the earlier of (C) the next interval in which the resource is dispatched to reduce load or (D) the end of the Operating Day. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time, refunding all payments due for Secondary Reserve during such period.

(iii) For Batch Load Economic Load Response Participant Resources, a second method of verification will be used for instances where a Secondary Reserve assignment dispatched as an energy load reduction is initiated and the resource is operating at the minimum consumption level of its duty cycle. In this case, the magnitude of the response will be measured as the difference between (A) the minimum of the resource's consumption between the minute before and the minute after the end of the last settlement interval the resource reduced load at the instruction of the Office of the Interconnection and (B) the maximum consumption within a ten (10) minute period following the end of the last settlement interval the resource reduced load provided that all subsequent minutes following that minute are no less than 50% of the consumption in that minute.

For each Batch Load Economic Load Response Participant Resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described in section (ii) above or the difference between (A) and (B) as described in section (iii) above, within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval, and for all prior intervals in which the resource was assigned to provide Secondary Reserve in either the Day-ahead or Real-time Secondary Reserve Markets between such non-performance event starting at the later of (A) the last interval the resource reduced load at the instruction of the Office of the Interconnection or (B) the beginning of that Operating Day, and for all subsequent intervals through the earlier of (C) the next interval in which the resource is dispatched to reduce load or (D) the end of the Operating Day. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time, refunding all payments due for Secondary Reserve during such period.

3.2.3A.02 Operating Reserve Demand Curves

(a) Operating Reserve Demand Curves

The Office of the Interconnection shall establish Operating Reserve Demand Curves for clearing 30-minute Reserve, Primary Reserve, and Synchronized Reserve, for, as applicable, each Reserve Zone or Reserve Sub-zone to procure sufficient reserves to meet reliability requirements in light of supply and demand uncertainties. The Operating Reserve Demand Curves established for each reserve type shall be used to commit such reserves in both the day-ahead and real-time reserve markets. The Operating Reserve Demand Curves shall be determined in accordance with subsection (b) and the PJM Manuals.

(b) Methodology for Establishing Operating Reserve Demand Curves

For each three-month season, Winter (December through February), Spring (March through May), Summer (June through August), and Fall (September through November), and for each time-of-day block set forth in the PJM Manuals, the Office of the Interconnection shall establish Operating Reserve Demand Curves for each Reserve Zone or Reserve Sub-zone as follows:

(i) Each Operating Reserve Demand Curve shall be plotted on a graph on which megawatts of reserve is on the x-axis and price is on the y-axis;

(ii) The Operating Reserve Demand Curve for each Reserve Zone or Reserve Sub-zone shall be plotted by combining (i) a straight horizontal line starting from point (1) on the y-axis to point (2), (ii) a straight vertical line connecting points (2) and (3), and (iv) a curved line from point (3) to the x-axis, where:

(A) Point (1) is the point on the y-axis(price) equal to the Reserve Penalty Factor for the minimum reserve requirement for the subject reserve requirement

(i.e., the Minimum 30-minute Reserve Requirement, the Minimum Primary Reserve Requirement, or the Minimum Synchronized Reserve Requirement);

(B) Point (2) has the y-axis coordinate of point (1) and the x-axis coordinate of the applicable minimum reserve requirement as determined for the Reserve Zone or Reserve Sub-zone in accordance with the PJM Manuals;

(C) Point (3) has the x-axis coordinate of the applicable minimum reserve requirement and the y-axis coordinate resulting from multiplying the Reserve Penalty Factor of the applicable minimum reserve requirement by the probability of falling below the applicable minimum reserve requirement when procuring an infinitesimal amount of additional MW of reserves beyond the minimum reserve requirement; and

(D) From point (3) to the x-axis, first, the Office of the Interconnection develops a curve starting at point (3). The shape of the curve will be determined by multiplying the Reserve Penalty Factor of the applicable minimum reserve requirement by the probability of falling below the applicable minimum reserve requirement when procuring each additional MW of reserves beyond the minimum reserve requirement until the resulting product falls below $0.01/MWh at which point the curve will intersect with the x-axis. These probabilities are calculated from an empirical distribution of data from a rolling three-calendar year period of the following supply and demand uncertainties, using a 30-minute time horizon for clearing Primary Reserves and Synchronized Reserves and a 60-minute time horizon for clearing 30-minute Reserves: load forecast error, wind forecast error, solar forecast error, and forced outages of thermal units, and, for the Operating Reserve Demand Curves for 30-minute Reserves only, net interchange forecast error, all as described in the PJM Manuals. The empirical distribution also accounts for the Regulation requirement, expressed in effective megawatts, that PJM has established for each hour within that time-of-day block, by reducing the magnitude of the above uncertainties by the requirement.

The Office of the Interconnection will post each Operating Reserve Demand Curve used to clear reserve markets.

(c) Annual Update of Operating Reserve Demand Curves

On an annual basis, the Office of the Interconnection shall update the determination of the probability of falling below the applicable minimum reserve requirement, including each uncertainty, to account for the most recent calendar year's data, in accordance with the PJM Manuals, and post revised Operating Reserve Demand Curves by April 1. The revised Operating Reserve Demand Curves shall become effective June 1, coincident with the start of the next Delivery Year.

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output, when positive, of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from a steam-electric generating unit, an Energy Storage Resource Model Participant, a Hybrid Resource, or a combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Tariff, Attachment K-Appendix, section 1.10.3(c) hereof), and where the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C. An Energy Storage Resource Model Participant or a Hybrid Resource instructed to reduce charging to provide Reactive Services is not eligible for compensation under section (c).

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Tariff, Attachment K-Appendix, section 1.10.3(c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost for each Real-time Settlement Interval, limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(e) At the end of each Operating Day, where the active energy output (positive generation output) of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to section 3.2.3B(f). At the end of each Operating Day, when an Energy Storage Resource Model Participant or a Hybrid Resource is instructed to increase charging at

the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from a steam-electric generating unit, an Energy Storage Resource Model Participant, a Hybrid Resource, a combined cycle unit, or a combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Tariff, Attachment K-Appendix, section 1.10.3(c) hereof), and where the real time LMP revenues at the unit's bus are lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit in an amount equal to {(AG ~~–~~ TRLD MWh~~LMPDMW~~) x (UB - URTLMP)}where:

AG equals the actual output of the unit;

TRLD MWh equals the Tracking Ramp Limited Desired MWh determined according to Tariff, Attachment K-Appendix, section 3.2.3(e-1)~~LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the real time LMP at the unit's bus and adjusted for any Regulation or Synchronized Reserve assignments~~;

UB equals the unit offer for that unit for which output, or charging, is increased, determined according to the lesser of the Final Offer or Committed Offer;

URTLMP equals the real time LMP at the unit's bus; and

where UB - URTLMP shall not be negative, except where applicable for an Energy Storage Resource Model Participant or a Hybrid Resource when instructed to increase charging.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Tariff, Attachment K-Appendix, section 1.10.3(c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability or if an Energy Storage Resource Model Participant or a Hybrid Resource believes the above calculations in this section 3.2.3B do not accurately compensate the Market Participant for opportunity costs associated with

following the Office of the Interconnection's dispatch instructions to modify a unit's charging or discharging for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate opportunity cost compensation, the Office of the Interconnection shall invoice the Market Participant accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in section 3.2.3A regarding provision of Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Synchronized Reserve Market Clearing Price for each Real-time Settlement Interval a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the product of the Condense Energy Use multiplied by the real time LMP at the generating unit's bus, (B) the generating unit's Condense Startup Cost, and (C) the unit-specific lost opportunity cost of the generating resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generating unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of the Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees in accordance with section 3.2.3(e-2). The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load ((a) net of operating Behind The Meter Generation; and (b) excluding Direct Charging Energy) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the applicable Synchronized Reserve Requirements. Operators of these generation units shall be

notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in section 3.2.3A regarding provision of 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Real-time Synchronized Reserve Market Clearing Price for each applicable interval a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the product of the Condense Energy Use multiplied by the real-time LMP at the generation bus of the generation resource, (B) the generation resource's Condense Startup Cost, and (C) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load ((a) net of operating Behind The Meter Generation; and (b) excluding Direct Charging Energy) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

Each Market Buyer shall be assessed Transmission Congestion Charges as specified in Tariff, Attachment K-Appendix, section 5.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Tariff, Attachment K-Appendix, section 5.

3.2.6 Emergency Energy.

(a) When the Office of the Interconnection has implemented Emergency procedures, resources offering Emergency energy are eligible to set real-time Locational Marginal Prices, capped at the energy offer cap plus sum of the applicable Reserve Penalty Factors for the Synchronized Reserved Requirement and Primary Reserve Requirement, provided that the Emergency energy is needed to meet demand in the PJM Region.

(b) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each applicable interval of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(c) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each applicable interval of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(d) The net costs or net revenues associated with sales or purchases of energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each applicable interval of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Participant in accordance with the charges and credits specified in sections 3.2.1 through 3.2.6, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Participant's internal accounting.

(b) If deliveries to a Market Participant that has PJM Interchange meters in accordance with Operating Agreement, section 14 include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market Participant, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market

Participant and the unmetered Market Participant specified by them to the Office of the Interconnection.

3.3A Economic Load Response Participants.

3.3A.1 Compensation.

Economic Load Response Participants shall be compensated pursuant to sections 3.3A.5 and/or 3.3A.6 of this Schedule, for demand reduction offers submitted in the Day-Ahead Energy Market or Real-time Energy Market that satisfy the Net Benefits Test of section 3.3A.4; that are scheduled by the Office of the Interconnection; and that follow the dispatch instructions of the Office of the Interconnection. Qualifying demand reductions shall be measured by: 1) comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of section 3.3A.2 or 3.3A.2.01, respectively; or 2) non-interval metered residential Direct Load Control customers, as metered on a current statistical sample of electric distribution company accounts, as described in the PJM Manuals or 3) by the MWs produced by on-Site Generators pursuant to the provisions of section 3.3A.2.02.

3.3A.2 Customer Baseline Load.

For Economic Load Response Participants that choose to measure demand reductions using an end-use customer's Customer Baseline Load ("CBL"), the CBL shall be determined using the following formula for such participant's Non-Variable Loads. Additionally, the following formula shall be used to determine a Peak Shaving Adjustment end-use customer's demand reductions when determining peak shaving performance rating as described in PJM Manual 19, unless an alternative CBL is approved pursuant to section 3.3A.2.01 of this schedule:

(a) The CBL for weekdays shall be the average of the highest 4 out of the 5 most recent load weekdays in the 45 calendar day period preceding the relevant load reduction event.

i. For the purposes of calculating the CBL for weekdays, weekdays shall not include:

1. NERC holidays;

2. Weekend days;

3. Event days. For the purposes of this section an event day shall be either:

(i) any weekday that an Economic Load Response Participant submits a settlement pursuant to section 3.3A.4 or 3.3A.5, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection; or

(ii) any weekday where the end-use customer location that is registered in the Economic Load Response program is also registered as a Demand Resource, and all end-use customer

locations on the relevant Economic Load Response registration have been dispatched by PJM during an emergency event.

4. Any weekday where the average daily event period usage is less than 25% of the average event period usage for the five days.

ii. If a 45-day period does not include 5 weekdays that meet the conditions in subsection (a)(i) of this section, provided there are 4 weekdays that meet the conditions in subsection (a)(i) of this section, the CBL shall be based on the average of those 4 weekdays. If there are not 4 eligible weekdays, the CBL shall be determined in accordance with subsection (iii) of this section.

iii. Section 3.3A.2(a)(i)(3) notwithstanding, if a 45-day period does not include 4 weekdays that meet the conditions in subsection (a)(i) of this section, event days will be used as necessary to meet the 4 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(b) The CBL for weekend days and NERC holidays shall be determined in accordance with the following provisions:

i. The CBL for Saturdays and Sundays/NERC holidays shall be the average of the highest 2 load days out of the 3 most recent Saturdays or Sundays/NERC holidays, respectively, in the 45 calendar day period preceding the relevant load reduction event, provided that the following days shall not be used to calculate a Saturday or Sunday/NERC holiday CBL:

1. Event days. For the purposes of this section an event day shall be either:

a. any Saturday and Sunday/NERC holiday that an Economic Load Response Participant submits a settlement pursuant to section 3.3A.5 or 3.3A.6, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection; or

b. any Saturday and Sunday/NERC holiday where the end-use customer that is registered in the Economic Load Response program is also registered as a Demand Resource, and all end-use customer locations on the relevant Economic Load Response registration have been dispatched by PJM during an emergency event.

2. Any Saturday or Sunday/NERC holiday where the average daily event period usage is less than 25% of the average event period usage level for the three days;

3. Any Saturday or Sunday/NERC holiday that corresponds to the beginning or end of daylight savings.

ii. If a 45-day period does not include 3 Saturdays or 3 Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, provided there are 2 Saturdays or Sundays/NERC holidays that meet the conditions in subsection (b)(i) of this section, the CBL will be based on the average of those 2 Saturdays or Sundays/NERC holidays. If there are not 2 eligible Saturdays or Sundays/NERC holidays, the CBL shall be determined in accordance with subsection (iii) of this section.

iii. Section 3.3A.2(b)(i)(1) notwithstanding, if a 45-day period does not include 2 Saturdays or Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, event days will be used as necessary to meet the 2 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(c) CBLs established pursuant to this section shall represent end-use customers' actual load patterns. If the Office of the Interconnection determines that a CBL or alternative CBL does not accurately represent a customer's actual load patterns, the CBL shall be revised accordingly pursuant to section 3.3A.2.01. Consistent with this requirement, if an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer upon whose behalf it is acting that would result in the adjustment of more than half the hours in the affected party's Customer Baseline Load by twenty percent or more for more than twenty days.

3.3A.2.01 Alternative Customer Baseline Methodologies.

(a) During the Economic Load Response Participant registration process pursuant to section 1.5A.3 of this Schedule, the relevant Economic Load Response Participant or the Office of the Interconnection ("Interested Parties") may, in the case of such participant's Non-Variable Load customers, and shall, in the case of its Variable Load customers, propose an alternative CBL calculation that more accurately reflects the relevant end-use customer's consumption pattern relative to the CBL determined pursuant to section 3.3A.2. During the Emergency and Pre-Emergency Load Response registration process pursuant to section 8.4 of this schedule, or as otherwise approved by the Office of the Interconnection, the relevant participant or the Office of the Interconnection may propose an alternative CBL calculation that more accurately reflects the relevant end-use customer's consumption pattern relative to the CBL determined pursuant to section 3.3A.2 of this schedule. In support of such proposal, the participant shall demonstrate that the alternative CBL method shall result in an hourly relative root mean square error of twenty percent or less compared to actual hourly values, as calculated in accordance with the technique specified in the PJM Manuals. Any proposal made pursuant to this section shall be provided to the other Interested Party.

(b) The Interested Parties shall have 30 days to agree on a proposal issued pursuant to subsection (a) of this section. The 30-day period shall start the day the proposal is provided to

the other Interested Party. If both Interested Parties agree on a proposal issued pursuant to this section, that alternative CBL calculation methodology shall be effective consistent with the date of the relevant Economic Load Response Participant registration.

(c) If agreement is not reached pursuant to subsection (b) of this section, the Office of the Interconnection shall determine a CBL methodology that shall result, as nearly as practicable, in an hourly relative root mean square error of twenty percent or less compared to actual hourly values within 20 days from the expiration of the 30-day period established by subsection (b). A CBL established by the Office of the Interconnection pursuant to this subsection (c) shall be binding upon both Interested Parties unless the Interested Parties reach agreement on an alternative CBL methodology prior to the expiration of the 20-day period established by this subsection (c).

(d) Operation of this section 3.3A.2.01 shall not delay Economic Load Response Participant registrations pursuant to Section 1.5A.3, provided that the alternative CBL established pursuant to this section shall be used for all related energy settlements made pursuant to sections 3.3A.5 and 3.3A.6.

(e) The Office of the Interconnection shall periodically publish alternative CBL methodologies established pursuant to this section in the PJM Manuals.

(f) Emergency and Pre-Emergency Load Response registrations will use the CBL defined on the associated economic registration for measuring demand reductions when determining the participant's compliance with its capacity obligations pursuant to Schedule 6 of the RAA, unless it is the maximum baseload CBL as defined in the PJM Manuals, in which case the participant will use the CBL set forth in the Emergency or Pre-Emergency Load Response registration.

3.3A.2.02 On-Site Generators.

On-Site Generators used as the basis for Economic Load Response Participant status pursuant to Tariff, Attachment K-Appendix, section 1.5A shall be subject to the following provisions:

i. The On-Site Generator shall be used solely to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market and shall not otherwise have been operating;

ii. If subsection (i) does not apply, the amount of energy from an On-Site Generator used to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market shall be capable of being quantified in a manner that is acceptable to the Office of the Interconnection.

3.3A.3 Symmetric Additive Adjustment.

(a) Customer Baseline Levels established pursuant to section 3.3A.2 shall be adjusted by the Symmetric Additive Adjustment. Unless an alternative formula is approved by the Office of the Interconnection, the Symmetric Additive Adjustment shall be calculated using the following formula:

Step 1: Calculate the average usage over the 3 hour period ending 1 hour prior to the start of event.

Step 2: Calculate the average usage over the 3 hour period in the CBL that corresponds to the 3 hour period described in Step 1.

Step 3: Subtract the results of Step 2 from the results of Step 1 to determine the symmetric additive adjustment (this may be positive or negative).

Step 4: Add the symmetric additive adjustment (i.e. the results of Step 3) to each hour in the CBL that corresponds to each event hour.

(b) Following a Load Reduction Event that is submitted to the Office of the Interconnection for compensation, the Office of the Interconnection shall provide the Notification window(s), if applicable, directly metered data and Customer Baseline Load and Symmetric Additive Adjustment calculation to the appropriate electric distribution company for optional review. The electric distribution company will have ten Business Days to provide the Office of the Interconnection with notification of any issues related to the metered data or calculations.

3.3A.4 Net Benefits Test.

The Office of the Interconnection shall identify each month the price on a supply curve, representative of conditions expected for that month, at which the benefit of load reductions provided by Economic Load Response Participants exceed the costs of those reductions to other loads. In formulaic terms, the net benefit is deemed to be realized at the price point on the supply curve where (Delta LMP x MWh consumed) > (LMP_{NEW} x DR), where LMP_{NEW} is the market clearing price after Economic Load Response is dispatched and Delta LMP is the price before Economic Load Response is dispatched minus the LMP_{NEW}).

The Office of the Interconnection shall update and post the Net Benefits Test results and analysis for a calendar month no later than the 15th day of the preceding calendar month. As more fully specified in the PJM Manuals, the Office of the Interconnection shall calculate the net benefit price level in accordance with the following steps:

Step 1. Retrieve generation offers from the same calendar month (of the prior calendar year) for which the calculation is being performed, employing market-based price offers to the extent available, and cost-based offers to the extent market-based price offers are not available. To the extent that generation offers are unavailable from historical data due to the addition of a Zone to the PJM Region the Office of the Interconnection shall use the most recent generation offers that

best correspond to the characteristics of the calendar month for which the calculation is being performed, provided that at least 30 days of such data is available. If less than 30 days of data is available for a resource or group of resources, such resource[s] shall not be considered in the Net Benefits Test calculation.

Step 2: Adjust a portion of each prior-year offer representing the typical share of fuel costs in energy offers in the PJM Region, as specified in the PJM Manuals, for changes in fuel prices based on the ratio of the reference month spot price to the study month forward price. For such purpose, natural gas shall be priced at the Henry Hub price, number 2 fuel oil shall be priced at the New York Harbor price, and coal shall be priced as a blend of coal prices representative of the types of coal typically utilized in the PJM Region.

Step 3. Combine the offers to create daily supply curves for each day in the period.

Step 4. Average the daily curves for each day in the month to form an average supply curve for the study month.

Step 5. Use a non-linear least squares estimation technique to determine an equation that reasonably approximates and smooths the average supply curve.

Step 6. Determine the net benefit level as the point at which the price elasticity of supply is equal to 1 for the estimated supply curve equation established in Step 5.

3.3A.5 Market Settlements in Real-time Energy Market.

(a) Economic Load Response Participants that submit offers for load reductions in the Day-ahead Energy Market by no later than 2:15 p.m. on the day prior to the Operating Day that cleared or that otherwise are dispatched by the Office of the Interconnection for the Operating Day shall be compensated for reducing demand based on the actual kWh relief provided in excess of committed day-ahead load reductions. The offer shall contain the Offer Data specified in Tariff, Attachment K-Appendix, section 1.10.1A(k) and shall not thereafter be subject to change; provided, however, the Economic Load Response Participant may update the previously specified minimum or maximum load reduction quantity and associated price by submitting a Real-time Offer for a clock hour by providing notice to the Office of the Interconnection in the form and manner specified in the PJM Manuals no later than 65 minutes prior to such clock hour. Economic Load Response Participants may also submit Real-time Offers for a clock hour for an Operating Day containing Offer Data specified in Tariff, Attachment K-Appendix, section 1.10.1A(k), and may update such offers up to 65 minutes prior to such clock hour. Economic Load Response Participants may, at their option, combine separately registered loads that have a common pricing point into a single portfolio for purposes of offering and dispatching their load reduction capability; provided however that any load reductions will continue to be measured and verified at the individual registration level prior to aggregation at the portfolio level for purposes of energy market and balancing ~~operating reserves~~energy uplift settlements. An Economic Load Response Participant that curtails or causes the curtailment of demand in real-time in response to PJM dispatch, and for which the

applicable real-time LMP is equal to or greater than the threshold price established under the Net Benefits Test, will be compensated by PJMSettlement at the real-time Locational Marginal Price.

(b) In cases where the demand reduction follows dispatch, as defined in Tariff, Attachment K-Appendix, section 3.2.3(o-1), as instructed by the Office of the Interconnection, and the demand reduction offer price is equal to or greater than the threshold price established under the Net Benefits Test, payment will not be less than the total value of the demand reduction bid. For the purposes of this subsection, the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing demand, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the demand reduction must be committed.

Any shortfall between the applicable Locational Marginal Price and the total value of the demand reduction bid will be made up through normal, ~~real-time operating reserves~~balancing Energy Make Whole credits. In all cases under this subsection, the applicable zonal or aggregate (including nodal) Locational Marginal Price shall be used as appropriate for the individual end-use customer. The foregoing notwithstanding, when calculating balancing Energy Make Whole credits for Economic Load Response Participants pursuant to Tariff, Attachment K-Appendix, section 3.2.3, the second Segment shall exclude shutdown costs.

(c) For purposes of load reductions qualifying for compensation hereunder, an Economic Load Response Participant shall accumulate credits for energy reductions in those hours when the energy delivered to the end-use customer is less than the end-use customer's Customer Baseline Load at the applicable Locational Marginal Price for the Real-time Settlement Interval. In the event that the end-use customer's hourly energy consumption is greater than the Customer Baseline Load, the Economic Load Response Participant will accumulate debits at the applicable Locational Marginal Price for the Real-time Settlement Interval for the amount the end-use customer's hourly energy consumption is greater than the Customer Baseline Load. If the actual load reduction, compared to the desired load reduction is outside the deviation levels specified in Tariff, Attachment K-Appendix, section 3.2.3(o-1), the Economic Load Response Participant shall be assessed balancing ~~operating reserve~~uplift charges equal to the Economic Load Response Participant's daily total of hourly deviations in each region times the regional adder rate for deviations in the relevant region plus the daily total of hourly deviations in the RTO region times the RTO region balancing uplift rate for deviations in accordance with Tariff, Attachment K-Appendix, section 3.2.3. The rates used for Economic Load Response Participant's balancing uplift charges are calculated in accordance with Tariff, Attachment K-Appendix, section 3.2.3(q-1), however the credits used in the calculation of the rates exclude balancing Energy Make Whole credits paid to Economic Load Response Participants. Market Participants with deviations in the RTO region, excluding Economic Load Response Participant deviations, shall be allocated any uplift credit associated with the collection of these charges.

(d) The cost of payments to Economic Load Response Participants under this section (excluding any portion of the payments recovered as ~~operating reserves~~balancing Energy Make Whole credits pursuant to subsection (b) of this section) for load reductions that are compensated at the applicable full LMP, in any Zone for any hour, shall be recovered from Market

Participants on a ratio-share basis based on their real-time exports from the PJM Region and from Load Serving Entities on a ratio-share basis based on their real-time loads in each Zone for which the load-weighted average Locational Marginal Price for the hour during which such load reduction occurred is greater than or equal to the price determined under the Net Benefits Test for that month, with the ratio shares determined as follows:

The ratio share for LSE **i** in zone **z** shall be $\mathbf{RTL_{iz}/(RTL + X)}$
and the ratio share for party **j** shall be $\mathbf{X_j/(RTL + X)}$.

Where:

RTL is the total real time load in all zones where LMP ≥ Net Benefits Test price;
$\mathbf{RTL_{iz}}$ is the real-time load for LSE **i** in zone **z**;
X is the total export quantity from PJM in that hour; and
$\mathbf{X_j}$ is the export quantity by party **j** from PJM.

3.3A.6 Market Settlements in the Day-ahead Energy Market.

(a) Economic Load Response Participants dispatched as a result of a qualifying demand reduction offer in the Day-ahead Energy Market shall be compensated for reducing demand based on the reductions of kWh committed in the Day-ahead Energy Market. An Economic Load Response Participant that submits a demand reduction bid day ahead that is accepted by the Office of the Interconnection and for which the applicable day ahead LMP is greater than or equal to the Net Benefits Test shall be compensated by PJMSettlement at the day-ahead Locational Marginal Price.

Economic Load Response Participants may, at their option, combine separately registered loads that have a common pricing point into a single portfolio for purposes of offering and dispatching their load reduction capability; provided however that any load reductions will continue to be measured and verified at the individual registration level prior to aggregation at the portfolio level for purposes of energy market and balancing ~~operating reserves~~uplift settlements.

(b) Total payments to Economic Load Response Participants for accepted day-ahead demand reduction bids with an offer price equal to or greater than the threshold price established under the Net Benefits Test that follow the dispatch instructions of the Office of the Interconnection will not be less than the total value of the demand reduction bid. For the purposes of this subsection, the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing load, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the load reduction must be committed. Any shortfall between the applicable Locational Marginal Price and the total value of the demand reduction bid will be made up through normal, day-ahead ~~operating reserves~~Energy Make Whole credits. In all cases under this subsection, the applicable zonal or aggregate (including nodal) Locational Marginal Price shall be used as appropriate for the individual end-use customer.

(c) Economic Load Response Participants that have demand reductions committed in the Day-ahead Energy Market that deviate from the day-ahead schedule in real time shall be charged or credited for such variance at the real time LMP plus or minus an amount equal to the applicable balancing ~~operating reserve~~uplift charge in accordance with Tariff, Attachment K-Appendix, section 3.2.3. Load Serving Entities that otherwise would have load that was reduced shall receive any associated ~~operating reserve~~uplift credit.

(d) The cost of payments to Economic Load Response Participants for accepted day-ahead demand reduction bids that are compensated at the applicable full, day ahead LMP under this section (excluding any portion of the payments recovered as ~~operating reserves~~day-ahead Energy Make Whole credits pursuant to subsection (b) of this section) for load reductions in any Zone for any hour shall be recovered from Market Participants on a ratio-share basis based on their real-time exports from the PJM Region and from Load Serving Entities on a ratio-share basis based on their real-time loads in each Zone for which the load-weighted average real-time Locational Marginal Price for the hour during which such load reduction occurred is greater than or equal to the price determined under the Net Benefits Test for that month, in accordance with the formula prescribed in Tariff, Attachment K-Appendix, section 3.3A.5(d).

3.3A.7 Prohibited Economic Load Response Participant Market Settlements.

(a) Settlements pursuant to sections 3.3A.5 and 3.3A.6 shall be limited to demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market that satisfy the Net Benefits Test and are dispatched by the Office of the Interconnection.

(b) Demand reductions that do not meet the requirements of section 3.3A.7(a) shall not be eligible for settlement pursuant to sections 3.3A.5 and 3.3A.6. Examples of settlements prohibited pursuant to this section 3.3A.7(b) include, but are not limited to, the following:

i. Settlements based on variable demand where the timing of the demand reduction supporting the settlement did not change in direct response to Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market;

ii. Consecutive daily settlements that are the result of a change in normal demand patterns that are submitted to maintain a CBL that no longer reflects the relevant end-use customer's demand;

iii. Settlements based on on-site generation data if the On-Site Generator is not supporting demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market;

iv. Settlements based on demand reductions that are the result of operational changes between multiple end-use customer sites in the PJM footprint;

v. Settlements that do not include all hours that the Office of the Interconnection dispatched the load reduction, or for which the load reduction cleared in the Day-ahead Market.

(c) The Office of the Interconnection shall disallow settlements for demand reductions that do not meet the requirements of section 3.3A.7(a). If the Economic Load Response Participant continues to submit settlements for demand reductions that do not meet the requirements of section 3.3A.7(a), then the Office of the Interconnection shall suspend the Economic Load Response Participant's PJM Interchange Energy Market activity and refer the matter to the FERC Office of Enforcement.

3.3A.8 Economic Load Response Participant Review Process.

(a) The Office of the Interconnection shall review the participation of an Economic Load Response Participant in the PJM Interchange Energy Market under the following circumstances:

i. An Economic Load Response Participant's registrations submitted pursuant to Tariff, Attachment K-Appendix, section 1.5A.3 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).

ii. An Economic Load Response Participant's settlements pursuant to sections 3.3A.5 and 3.3A.6 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).

iii. An Economic Load Response Participant's settlements pursuant to sections 3.3A.5 and 3.3A.6 are denied by the Office of the Interconnection more than 10% of the time.

iv. An Economic Load Response Participant's registration will be reviewed when settlements are frequently submitted or if its actual loads frequently deviate from the previously scheduled quantities (as determined for purposes of assessing balancing ~~operating reserves~~uplift charges). PJM will notify the Participant when their registration is under review. While the Participant's registration is under review by PJM, the Participant may continue economic load reductions but all settlements will be denied by PJM until the registration review is resolved pursuant to subsection (i) or (ii) below. PJM will require the Participant to provide information within 30 days to support that the settlements were submitted for load reduction activity done in response to price and not submitted based on the end-use customer's normal operations.

i) If the Participant is unable to provide adequate supporting information to substantiate the load reductions submitted for settlement, PJM will terminate the registration and may refer the Participant to either the Market Monitoring Unit or the Federal Energy Regulatory Commission for further investigation.

ii) If the Participant does provide adequate supporting information, the settlements denied by PJM will be resubmitted by the Participant for review according to existing PJM market rules. Further, PJM may introduce an alternative Customer Baseline Load if the existing Customer Baseline Load does not adequately reflect what the customer load would have been absent a load reduction.

v. The electric distribution company may only deny settlements during the normal settlement review process for inaccurate data including, but not limited to: meter data, line loss factor, Customer Baseline Load calculation, interval meter owner and a known recurring end-use customer outage or holiday.

(b) The Office of the Interconnection shall have thirty days to conduct a review pursuant to this section 3.3A.8. The Office of the Interconnection may refer the matter to the PJM MMU and/or the FERC Office of Enforcement if the review indicates the relevant Economic Load Response Participant and/or relevant electric distribution company or LSE is engaging in activity that is inconsistent with the PJM Interchange Energy Market rules governing Economic Load Response Participants.

8.8 Market Settlements

Payment for reducing load is based on the actual kWh relief provided plus the adjustment for losses, subject to the Reporting and Compliance provisions below. The magnitude of capacity relief provided by Full Program Option participants shall be the amount determined in accordance with the Reporting and Compliance provisions below. The magnitude of relief provided by Energy Only Option participants, and the magnitude of energy relief provided by Full Program Option participants, may be less than, equal to, or greater than the kW amount declared on the Emergency or Pre-Emergency registration. Compensation will be provided for reductions in energy consumption during emergency events, tests and associated retest(s), where applicable by Full Program Option participants and Energy Only Option participants regardless of whether the participant's load during the event exceeds its peak load contribution for the applicable Delivery Year.

PJMSettlement pays the applicable LMP to the PJM Member that nominates the load. Payment will be equal to the measured energy load reduction adjusted for losses times the applicable LMP. The measured energy load reduction for locations with approved Economic Load Response registrations prior to a Load Management Event that have an economic CBL different than the maximum base load as defined in the PJM Manuals will use the associated economic CBL to determine the energy load reduction unless the locations on the Emergency Load Response registration are not the same locations as those included on the Economic Load Response registration. If, at the time that a Load Management Event or emergency event is initiated by PJM, an end-use customer is already responding economically (i.e., pursuant to the Economic Load Response rules) and economic CBL is based on Symmetric Additive Adjustment, then the CBL calculated based on the Symmetric Additive Adjustment period prior to the economic event will be used. Locations that do not have an approved Economic Load Response registration prior to a Load Management Event will use the Customer Baseline Load as defined in section 3.3A.2 and associated Symmetric Additive Adjustment as defined in section 3.3A.2.01 of this schedule unless an alternative CBL is approved pursuant to section 3.3A.2.01 of this schedule as the CBL to determine the energy load reduction.

If, however, the sum of the hourly energy payments to a Curtailment Service Provider with a Demand Resource Registration dispatched by PJM for actual, achieved reductions for an emergency event is not greater than or equal to the offer value (i.e. Minimum Dispatch Price and shut down costs) then the Curtailment Service Provider will be made whole up to the offer value for its actual, achieved reductions for the Demand Resource Registration.

Locations on Economic Load Response registrations dispatched in the Real-time Energy Market or cleared in the Day-ahead Energy Market that are also included on an Emergency Load Response and Pre-Emergency Load Response registration as Full Program Option, and that have also been dispatched as part of an emergency event for the same hour (i.e., have an "overlapping dispatch hour") will be compensated for energy based on emergency energy settlement and cost allocation rules as set forth in this section and in the PJM Manuals. Overlapping dispatch hours will use shutdown costs based on what was considered for the economic event, and no balancing ~~Operating Reserve~~uplift charges will be assessed for deviations from real-time dispatch amounts or from cleared day-ahead commitments. To avoid duplicative energy payments, overlapping dispatch hours for an aggregate registration (i.e., multiple locations on the same registration) or

dispatch groups where locations on the Emergency Load Response and Pre-Emergency Load Response registration are not the same locations as those on the Economic Load Response registration will have hourly economic energy load reduction and/or hourly emergency energy load reduction prorated based on load reduction capability provided by the Curtailment Service Provider for the locations.

The Curtailment Service Provider will only submit energy settlements for Load Management Events that occur outside of the specific availability period defined in the Reliability Assurance Agreement for each Demand Resource type if the Curtailment Service Provider has confirmed that the customers on the registration did take action to reduce load or the registration reflects the entire group of mass market customers for which an energy settlement will either be submitted for all or none of the mass market customers, as approved by PJM. The Curtailment Service Provider will only submit energy settlements for tests and for each registration for Load Management Events that occur during the product specific availability period as defined for each product in the Reliability Assurance Agreement if the Curtailment Service Provider also provides associated load data for each registration in order to calculate that registration's capacity compliance.

Full Program Option participants that fail to provide a load reduction (as measured as set forth in the Reporting and Compliance provisions below) when dispatched by PJM shall be assessed penalties and/or charges as specified in Tariff, Attachment DD and the Reliability Assurance Agreement, as applicable.

During emergency conditions, costs for emergency purchases in excess of LMP are allocated among PJM Market Buyers in proportion to their increase in net purchases minus real-time dispatch reduction megawatts from the PJM energy market during the hour in the Real-time Energy Market compared to the Day-ahead Energy Market. Consistent with this pricing methodology, all charges under the Emergency Load Response and Pre-Emergency Load Response Program are allocated to purchasers of energy, in proportion to their increase in net purchases minus real-time dispatch reduction megawatts from the PJM energy market during the hour from day-ahead to real-time.

The cost of payments for Emergency Load Response and Pre-Emergency Load Response energy settlements for tests, shall be recovered from Market Participants on a ratio-share basis based on their real-time exports from the PJM Region and from Load Serving Entities on ratio-share basis based on their real-time loads in each Zone for that month where the tests were conducted, with the ratio shares determined as follows:

The ratio share for LSE i in zone z shall be RTLiz/(RTL + X)
and the ratio share for party j shall be Xj/(RTL + X).
Where:

RTL is the total real time load in all zones where Load Management was tested;
RTLiz is the real-time load for LSE i in zone z;
X is the total export quantity from PJM in that hour; and
Xj is the export quantity by party j from PJM.

Emergency Load Response and Pre-Emergency Load Response Program charges and credits will appear on the PJM Members monthly bill, as described in the ***PJM Manual for Operating Agreement Accounting and the PJM Manual for Billing.***

Revisions to the
PJM Open Access Transmission Tariff

(Clean Format)

Definitions – A - B

30-minute Reserve:

"30-minute Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within 30 minutes of a request from the Office of the Interconnection dispatcher, and is comprised of Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve.

30-minute Reserve Requirement:

"30-minute Reserve Requirement" shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone, as Secondary Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The 30-minute Reserve Requirement is calculated in accordance with the PJM Manuals. The requirement can be satisfied by any combination of Synchronized Reserve, Non Synchronized Reserve or Secondary Reserve resources.

Abnormal Condition:

"Abnormal Condition" shall mean any condition on the Interconnection Facilities which, determined in accordance with Good Utility Practice, is: (i) outside normal operating parameters such that facilities are operating outside their normal ratings or that reasonable operating limits have been exceeded; and (ii) could reasonably be expected to materially and adversely affect the safe and reliable operation of the Interconnection Facilities; but which, in any case, could reasonably be expected to result in an Emergency Condition. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not, standing alone, constitute an Abnormal Condition.

Acceleration Request:

"Acceleration Request" shall mean a request pursuant to Operating Agreement, Schedule 1, section 1.9.4A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.4A, to accelerate or reschedule a transmission outage scheduled pursuant to Operating Agreement, Schedule 1, section 1.9.2 or Operating Agreement, Schedule 1, section 1.9.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.2 or Tariff, Attachment K-Appendix, section 1.9.4.

Actual MWh

"Actual MWh" is equal to the real-time output of a resource as defined by the Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Tariff, Attachment K-Appendix, section 3.1A and parallel provisions in Operating Agreement, Schedule 1, section 3.1A.

Affected System:

"Affected System" shall mean an electric system other than the Transmission Provider's Transmission System that may be affected by a proposed interconnection or on which a proposed interconnection or addition of facilities or upgrades may require modifications or upgrades to the Transmission System.

Affected System Operator:

"Affected System Operator" shall mean an entity that operates an Affected System or, if the Affected System is under the operational control of an independent system operator or a regional transmission organization, such independent entity.

Affiliate:

"Affiliate" shall mean any two or more entities, one of which Controls the other or that are under common Control. "Control," as that term is used in this definition, shall mean the possession, directly or indirectly, of the power to direct the management or policies of an entity. Ownership of publicly-traded equity securities of another entity shall not result in Control or affiliation for purposes of the Tariff or Operating Agreement if the securities are held as an investment, the holder owns (in its name or via intermediaries) less than 10 percent (10%) of the outstanding securities of the entity, the holder does not have representation on the entity's board of directors (or equivalent managing entity) or vice versa, and the holder does not in fact exercise influence over day-to-day management decisions. Unless the contrary is demonstrated to the satisfaction of the Members Committee, Control shall be presumed to arise from the ownership of or the power to vote, directly or indirectly, ten percent or more of the voting securities of such entity.

Agreements:

"Agreements" shall mean the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., the PJM Open Access Transmission Tariff, the Reliability Assurance Agreement, and/or other agreements between PJM Interconnection, L.L.C. and its Members.

Ancillary Services:

"Ancillary Services" shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

Annual Demand Resource:

"Annual Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

Annual Energy Efficiency Resource:

"Annual Energy Efficiency Resource" shall have the meaning specified in the Reliability Assurance Agreement.

Annual Resource:

"Annual Resource" shall mean a Generation Capacity Resource, an Annual Energy Efficiency Resource or an Annual Demand Resource.

Annual Revenue Rate:

"Annual Revenue Rate" shall mean the rate employed to assess a compliance penalty charge on a Curtailment Service Provider under Tariff, Attachment DD, section 11.

Annual Transmission Costs:

"Annual Transmission Costs" shall mean the total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H for each Zone until amended by the applicable Transmission Owner or modified by the Commission.

Applicable Laws and Regulations:

"Applicable Laws and Regulations" shall mean all duly promulgated applicable federal, State and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority having jurisdiction over the relevant parties, their respective facilities, and/or the respective services they provide.

Applicable Regional Entity:

"Applicable Regional Entity" shall mean the Regional Entity for the region in which a Network Customer, Transmission Customer, New Service Customer, or Transmission Owner operates.

Applicable Standards:

"Applicable Standards" shall mean the requirements and guidelines of NERC, the Applicable Regional Entity, and the Control Area in which the Customer Facility is electrically located; the PJM Manuals; and Applicable Technical Requirements and Standards.

Applicable Technical Requirements and Standards:

"Applicable Technical Requirements and Standards" shall mean those certain technical requirements and standards applicable to interconnections of generation and/or transmission facilities with the facilities of an Interconnected Transmission Owner or, as the case may be and to the extent applicable, of an Electric Distributor, as published by Transmission Provider in a PJM Manual provided, however, that, with respect to any generation facilities with maximum generating capacity of 2 MW or less (synchronous) or 5 MW or less (inverter-based) for which the Interconnection Customer executes a Construction Service Agreement or Interconnection

Service Agreement on or after March 19, 2005, "Applicable Technical Requirements and Standards" shall refer to the "PJM Small Generator Interconnection Applicable Technical Requirements and Standards." All Applicable Technical Requirements and Standards shall be publicly available through postings on Transmission Provider's internet website.

Applicant:

"Applicant" shall mean an entity desiring to become a PJM Member, become a Market Participant, engage in market activities, or to take Transmission Service that has submitted the PJMSettlement credit application, PJMSettlement credit agreement and other required submittals as set forth in Tariff, Attachment Q.

Application:

"Application" shall mean a request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

Attachment Facilities:

"Attachment Facilities" shall mean the facilities necessary to physically connect a Customer Facility to the Transmission System or interconnected distribution facilities.

Attachment H:

"Attachment H" shall refer collectively to the Attachments to the PJM Tariff with the prefix "H" that set forth, among other things, the Annual Transmission Rates for Network Integration Transmission Service in the PJM Zones.

Auction Revenue Rights:

"Auction Revenue Rights" or "ARRs" shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Operating Agreement, Schedule 1, section 7.4, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.

Auction Revenue Rights Credits:

"Auction Revenue Rights Credits" shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Authorized Government Agency:

"Authorized Government Agency" means a regulatory body or government agency, with jurisdiction over PJM, the PJM Market, or any entity doing business in the PJM Market, including, but not limited to, the Commission, State Commissions, and state and federal attorneys general.

Avoidable Cost Rate:

"Avoidable Cost Rate" shall mean a component of the Market Seller Offer Cap calculated in accordance with Tariff, Attachment DD, section 6.

Balancing Congestion Charges:

"Balancing Congestion Charges" shall be equal to the sum of congestion charges collected from Market Participants that are purchasing energy in the Real-time Energy Market minus [the sum of congestion charges paid to Market Participants that are selling energy in the Real-time Energy Market plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, plus any charges or credits calculated pursuant to Operating Agreement, Schedule 1, section 3.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 3.8, as applicable)].

Balancing Ratio:

"Balancing Ratio" shall have the meaning provided in Tariff, Attachment DD, section 10A.

Base Load Generation Resource

"Base Load Generation Resource" shall mean a Generation Capacity Resource that operates at least 90 percent of the hours that it is available to operate, as determined by the Office of the Interconnection in accordance with the PJM Manuals.

Base Offer Segment:

"Base Offer Segment" shall mean a component of a Sell Offer based on an existing Generation Capacity Resource, equal to the Unforced Capacity of such resource, as determined in accordance with the PJM Manuals. If the Sell Offers of multiple Market Sellers are based on a single Existing Generation Capacity Resource, the Base Offer Segments of such Market Sellers shall be determined pro rata based on their entitlements to Unforced Capacity from such resource.

Base Residual Auction:

"Base Residual Auction" shall mean the auction conducted three years prior to the start of the Delivery Year to secure commitments from Capacity Resources as necessary to satisfy any portion of the Unforced Capacity Obligation of the PJM Region not satisfied through Self-Supply.

Batch Load Economic Load Response Participant Resource:

"Batch Load Economic Load Response Participant Resource" shall mean an Economic Load Response Participant Resource that has a cyclical production process such that at most times during the process it is consuming energy, but at consistent regular intervals, ordinarily for periods of less than ten minutes, it reduces its consumption of energy for its production processes to minimal or zero megawatts.

Behind The Meter Generation:

"Behind The Meter Generation" shall refer to a generation unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of the Interconnection); provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit's capacity that is designated as a Generation Capacity Resource; or (ii) in an hour, any portion of the output of such generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

Black Start Service:

"Black Start Service" shall mean the capability of generating units to start without an outside electrical supply or the demonstrated ability of a generating unit with a high operating factor (subject to Transmission Provider concurrence) to automatically remain operating at reduced levels when disconnected from the grid.

Border Yearly Charge:

"Border Yearly Charge" shall mean the yearly charge determined in accordance with Tariff, Schedule 7.

Breach:

"Breach" shall mean the failure of a party to perform or observe any material term or condition of Tariff, Part IV or Tariff, Part VI, or any agreement entered into thereunder as described in the relevant provisions of such agreement.

Breaching Party:

"Breaching Party" shall mean a party that is in Breach of Tariff, Part IV or Tariff, Part VI and/or an agreement entered into thereunder.

Business Day:

"Business Day" shall mean a day in which the Federal Reserve System is open for business and

is not a scheduled PJM holiday.

Buy Bid:

“Buy Bid” shall mean a bid to buy Capacity Resources in any Incremental Auction.

Buyer-Side Market Power:

“Buyer-Side Market Power” shall mean the ability of Capacity Market Sellers with a Load Interest to suppress RPM Auction clearing prices for the overall benefit of their (and/or affiliates) portfolio of generation and load.

Definitions – E - F

Economic-based Enhancement or Expansion:

"Economic-based Enhancement or Expansion" shall have the same meaning provided in the Operating Agreement.

Economic Load Response Participant:

"Economic Load Response Participant" shall mean a Member or Special Member that qualifies under Operating Agreement, Schedule 1, section 1.5A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A, to participate in the PJM Interchange Energy Market and/or Ancillary Services markets through reductions in demand.

Economic Maximum:

"Economic Maximum" shall mean the highest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Economic Minimum:

"Economic Minimum" shall mean the lowest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Effective FTR Holder:

"Effective FTR Holder" shall mean:

(i) For an FTR Holder that is either a (a) privately held company, or (b) a municipality or electric cooperative, as defined in the Federal Power Act, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other entity that is under common ownership, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or

(ii) For an FTR Holder that is a publicly traded company including a wholly owned subsidiary of a publicly traded company, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other PJM Member has over 10% common ownership with the FTR Holder, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or

(iii) an FTR Holder together with any other PJM Member, including also any Affiliate, subsidiary or parent of such other PJM Member, with which it shares common ownership, wholly or partly, directly or indirectly, in any third entity which is a PJM Member (e.g., a joint venture).

EFORd:

"EFORd" shall have the meaning specified in the PJM Reliability Assurance Agreement.

Electrical Distance:

"Electrical Distance" shall mean, for a Generation Capacity Resource geographically located outside the metered boundaries of the PJM Region, the measure of distance, based on impedance and in accordance with the PJM Manuals, from the Generation Capacity Resource to the PJM Region.

Eligible Customer:

"Eligible Customer" shall mean:

(i) Any electric utility (including any Transmission Owner and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider or Transmission Owner offer the unbundled transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner.

(ii) Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider or a Transmission Owner offer the transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner, is an Eligible Customer under the Tariff. As used in Tariff, Part VI, Eligible Customer shall mean only those Eligible Customers that have submitted a Completed Application.

Eligible Fast-Start Resource:

"Eligible Fast-Start Resource" shall mean a Fast-Start Resource that is eligible for the application of Integer Relaxation during the calculation of Locational Marginal Prices as set forth in Tariff, Attachment K-Appendix, section 2.2.

Emergency Action:

"Emergency Action" shall mean (1) any megawatt shortage of the Primary Reserve Requirement (as specified in the PJM Manuals) in a Reserve Zone or Reserve Sub-zone, inclusive of any adjustments to such requirement to account for system conditions, as determined by the dispatch run from the security constrained economic dispatch and where, as specified in the PJM Manuals, there is also a Voltage Reduction Warning and reduction of non-critical plant load, Manual Load Dump Warning, Maximum Generation Emergency Action, or the curtailment of

non-essential building loads and Voltage Reduction Warning that encompasses such Reserve Zone or Reserve Sub-zone or (2) anytime the Office of Interconnection identifies an emergency and issues a load shed directive, Manual Load Dump Action, Voltage Reduction Action, or deploy all resources action for an entire Reserve Zone or Reserve Sub-zone.

Emergency Condition:

"Emergency Condition" shall mean a condition or situation (i) that in the judgment of any Interconnection Party is imminently likely to endanger life or property; or (ii) that in the judgment of the Interconnected Transmission Owner or Transmission Provider is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Transmission System, the Interconnection Facilities, or the transmission systems or distribution systems to which the Transmission System is directly or indirectly connected; or (iii) that in the judgment of Interconnection Customer is imminently likely (as determined in a non-discriminatory manner) to cause damage to the Customer Facility or to the Customer Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions, provided that a Generation Interconnection Customer is not obligated by an Interconnection Service Agreement to possess black start capability. Any condition or situation that results from lack of sufficient generating capacity to meet load requirements or that results solely from economic conditions shall not constitute an Emergency Condition, unless one or more of the enumerated conditions or situations identified in this definition also exists.

Emergency Load Response Program:

"Emergency Load Response Program" shall mean the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during emergency conditions, and is described in Operating Agreement, Schedule 1, section 8 and the parallel provisions of Tariff, Attachment K-Appendix, section 8.

Energy Efficiency Resource:

"Energy Efficiency Resource" shall have the meaning specified in the PJM Reliability Assurance Agreement.

Energy Make Whole

"Energy Make Whole" shall refer to energy uplift provided to make a resource whole for costs incurred as specified in Tariff, Attachment K-Appendix, section 3.2.3 and parallel provisions in Operating Agreement, Schedule 1, section 3.2.3.

Energy Market Opportunity Cost:

"Energy Market Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of available run hours due to limitations imposed on the unit by Applicable Laws and Regulations, and (b) the forecasted future Locational Marginal Price at which the generating unit could run while not

violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Energy Resource:

"Energy Resource" shall mean a Generating Facility that is not a Capacity Resource.

Energy Settlement Area:

"Energy Settlement Area" shall mean the bus or distribution of busses that represents the physical location of Network Load and by which the obligations of the Network Customer to PJM are settled.

Energy Storage Resource:

"Energy Storage Resource" shall mean a resource capable of receiving electric energy from the grid and storing it for later injection to the grid that participates in the PJM Energy, Capacity and/or Ancillary Services markets as a Market Participant. Open-Loop Hybrid Resources are not Energy Storage Resources.

Energy Storage Resource Model Participant:

"Energy Storage Resource Model Participant" shall mean an Energy Storage Resource utilizing the Energy Storage Resource Participation Model.

Energy Storage Resource Participation Model:

"Energy Storage Resource Participation Model" shall mean the participation model accepted by the Commission in Docket No. ER19-469-000.

Energy Transmission Injection Rights:

"Energy Transmission Injection Rights" shall mean the rights to schedule energy deliveries at a specified point on the Transmission System. Energy Transmission Injection Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System to another control area. Deliveries scheduled using Energy Transmission Injection Rights have rights similar to those under Non-Firm Point-to-Point Transmission Service.

Entity Providing Supply Services to Default Retail Service Provider:

"Entity Providing Supply Services to Default Retail Service Provider" shall mean any entity, including but not limited to a load aggregator or power marketer, providing supply services to an

electric distribution company when that electric distribution company is serving as the default retail service provider, and that enters into a contract or similar obligation with such electric distribution company to serve retail customers who have not selected a competitive retail service provider.

Environmental Laws:

"Environmental Laws" shall mean applicable Laws or Regulations relating to pollution or protection of the environment, natural resources or human health and safety.

Environmentally-Limited Resource:

"Environmentally-Limited Resource" shall mean a resource which has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited by a governmental authority to operating only during declared PJM capacity emergencies.

Equivalent Load:

"Equivalent Load" shall mean the sum of a Market Participant's net system requirements to serve its customer load in the PJM Region, if any, plus its net bilateral transactions.

Event of Default:

"Event of Default," as that term is used in Tariff, Attachment Q, shall mean a Financial Default, Credit Breach, or Credit Support Default.

Exercise of Buyer-Side Market Power:

"Exercise of Buyer-Side Market Power" shall mean anti-competitive behavior of a Capacity Market Seller with a Load Interest, or directed by an entity with a Load Interest, to uneconomically lower RPM Auction Sell Offer(s) in order to suppress RPM Auction clearing prices for the overall benefit of the Capacity Market Seller's (and/or affiliates of Capacity Market Seller) portfolio of generation and load or that of the directing entity with a Load Interest as determined pursuant to Tariff, Attachment DD, section 5.14(h-2)(2)(B). A bilateral contract between the Capacity Market Seller and an entity with a Load Interest with the express purpose of lowering capacity market clearing prices shall be evidence of the Exercise of Buyer-Side Market Power.

Existing Generation Capacity Resource:

"Existing Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

Export Credit Exposure:

"Export Credit Exposure" is determined for each Market Participant for a given Operating Day, and shall mean the sum of credit exposures for the Market Participant's Export Transactions for that Operating Day and for the preceding Operating Day.

Export Nodal Reference Price:

"Export Nodal Reference Price" at each location is the 97th percentile, shall be, the real-time hourly integrated price experienced over the corresponding two-month period in the preceding calendar year, calculated separately for peak and off-peak time periods. The two-month time periods used in this calculation shall be January and February, March and April, May and June, July and August, September and October, and November and December.

Export Transaction:

"Export Transaction" shall be a transaction by a Market Participant that results in the transfer of energy from within the PJM Control Area to outside the PJM Control Area. Coordinated External Transactions that result in the transfer of energy from the PJM Control Area to an adjacent Control Area are one form of Export Transaction.

Export Transaction Price Factor:

"Export Transaction Price Factor" for a prospective time interval shall be the greater of (i) PJM's forecast price for the time interval, if available, or (ii) the Export Nodal Reference Price, but shall not exceed the Export Transaction's dispatch ceiling price cap, if any, for that time interval. The Export Transaction Price Factor for a past time interval shall be calculated in the same manner as for a prospective time interval, except that the Export Transaction Price Factor may use a tentative or final settlement price, as available. If an Export Nodal Reference Price is not available for a particular time interval, PJM may use an Export Transaction Price Factor for that time interval based on an appropriate alternate reference price.

Export Transaction Screening:

"Export Transaction Screening" shall be the process PJM uses to review the Export Credit Exposure of Export Transactions against the Credit Available for Export Transactions, and deny or curtail all or a portion of an Export Transaction, if the credit required for such transactions is greater than the credit available for the transactions.

Export Transactions Net Activity:

"Export Transactions Net Activity" shall mean the aggregate net total, resulting from Export Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Operating Agreement, Schedule 1 and the parallel provisions of Tariff, Attachment K-Appendix. Export Transactions Net Activity may be positive or negative.

Extended Primary Reserve Requirement:

"Extended Primary Reserve Requirement" shall equal the Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

Extended Synchronized Reserve Requirement:

"Extended Synchronized Reserve Requirement" shall equal the Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

Extended 30-minute Reserve Requirement:

"Extended 30-minute Reserve Requirement" shall equal the 30-minute Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended 30-minute Reserve Requirement is calculated in accordance with the PJM Manuals.

External Market Buyer:

"External Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for consumption by end-users outside the PJM Region, or for load in the PJM Region that is not served by Network Transmission Service.

External Resource:

"External Resource" shall mean a generation resource located outside the metered boundaries of the PJM Region.

Facilities Study:

"Facilities Study" shall be an engineering study conducted by the Transmission Provider (in coordination with the affected Transmission Owner(s)) to: (1) determine the required modifications to the Transmission Provider's Transmission System necessary to implement the conclusions of the System Impact Study; and (2) complete any additional studies or analyses documented in the System Impact Study or required by PJM Manuals, and determine the required modifications to the Transmission Provider's Transmission System based on the conclusions of such additional studies. The Facilities Study shall include the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service or to accommodate a New Service Request. As used in the Interconnection Service Agreement or Construction Service Agreement, Facilities Study shall mean that certain Facilities Study conducted by Transmission Provider (or at its direction) to determine the design and specification of the Customer Funded Upgrades necessary to accommodate the New Service Customer's New Service Request in accordance with Tariff, Part VI, section 207.

Fast-Start Resource:

"Fast-Start Resource" shall have the meaning set forth in Tariff, Attachment K-Appendix, section 2.2A

Federal Power Act:

"Federal Power Act" shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a, et seq.

FERC or Commission:

"FERC" or "Commission" shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over the Tariff, Operating Agreement and Reliability Assurance Agreement.

FERC Market Rules:

"FERC Market Rules" mean the market behavior rules and the prohibition against electric energy market manipulation codified by the Commission in its Rules and Regulations at 18 CFR §§ 1c.2 and 35.37, respectively; the Commission-approved PJM Market Rules and any related proscriptions or any successor rules that the Commission from time to time may issue, approve or otherwise establish.

Final Offer:

"Final Offer" shall mean the offer on which a resource was dispatched by the Office of the Interconnection for a particular clock hour for the Operating Day.

Final RTO Unforced Capacity Obligation:

"Final RTO Unforced Capacity Obligation" shall mean the capacity obligation for the PJM Region, determined in accordance with RAA, Schedule 8.

Financial Close:

"Financial Close" shall mean the Capacity Market Seller has demonstrated that the Capacity Market Seller or its agent has completed the act of executing the material contracts and/or other documents necessary to (1) authorize construction of the project and (2) establish the necessary funding for the project under the control of an independent third-party entity. A sworn, notarized certification of an independent engineer certifying to such facts, and that the engineer has personal knowledge of, or has engaged in a diligent inquiry to determine, such facts, shall be sufficient to make such demonstration. For resources that do not have external financing, Financial Close shall mean the project has full funding available, and that the project has been duly authorized to proceed with full construction of the material portions of the project by the appropriate governing body of the company funding such project. A sworn, notarized

certification by an officer of such company certifying to such facts, and that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, such facts, shall be sufficient to make such demonstration.

Financial Default:

"Financial Default" shall mean (a) the failure of a Member or Transmission Customer to make any payment for obligations under the Agreements when due, including but not limited to an invoice payment that has not been cured or remedied after notice has been given and any cure period has elapsed, (b) a bankruptcy proceeding filed by a Member, Transmission Customer or its Guarantor, or filed against a Member, Transmission Customer or its Guarantor and to which the Member, Transmission Customer or Guarantor, as applicable, acquiesces or that is not dismissed within 60 days, (c) a Member, Transmission Customer or its Guarantor, if any, is unable to meet its financial obligations as they become due, or (d) a Merger Without Assumption occurs in respect of the Member, Transmission Customer or any Guarantor of such Member or Transmission Customer.

Financial Transmission Right:

"Financial Transmission Right" or "FTR" shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2.

Financial Transmission Right Obligation:

"Financial Transmission Right Obligation" shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(b), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(b).

Financial Transmission Right Option:

"Financial Transmission Right Option" shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(c), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(c).

Firm Point-To-Point Transmission Service:

"Firm Point-To-Point Transmission Service" shall mean Transmission Service under the Tariff, Part II, section 13 that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Tariff, Part II.

Firm Transmission Feasibility Study:

"Firm Transmission Feasibility Study" shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part II, section 19.3 and Tariff, Part III, section 32.3.

Firm Transmission Withdrawal Rights:

"Firm Transmission Withdrawal Rights" shall mean the rights to schedule energy and capacity withdrawals from a Point of Interconnection of a Merchant Transmission Facility with the Transmission System. Firm Transmission Withdrawal Rights may be awarded only to a Merchant D.C. Transmission Facility that connects the Transmission System with another control area. Withdrawals scheduled using Firm Transmission Withdrawal Rights have rights similar to those under Firm Point-to-Point Transmission Service.

First Incremental Auction:

"First Incremental Auction" shall mean an Incremental Auction conducted 20 months prior to the start of the Delivery Year to which it relates.

Flexible Resource:

"Flexible Resource" shall mean a generating resource that must have a combined Start-up Time and Notification Time of less than or equal to two hours; and a Minimum Run Time of less than or equal to two hours.

Forecast Pool Requirement:

"Forecast Pool Requirement" shall have the meaning specified in the Reliability Assurance Agreement.

Foreign Guaranty:

"Foreign Guaranty" shall mean a Corporate Guaranty provided by an Affiliate of a Participant that is domiciled in a foreign country, and meets all of the provisions of Tariff, Attachment Q.

Form 715 Planning Criteria:

"Form 715 Planning Criteria" shall have the same meaning provided in the Operating Agreement.

Forward Daily Natural Gas Prices:

"Forward Daily Natural Gas Prices" shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(E).

Forward Hourly Ancillary Services Prices:

"Forward Hourly Ancillary Services Prices" shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(D).

Forward Hourly LMPs:

"Forward Hourly LMPs" shall have the meaning provided in Tariff, Attachment DD, section 5.10(a)(v-1)(C).

FTR Credit Limit:

"FTR Credit Limit" shall mean the amount of credit established with PJMSettlement that an FTR Participant has specifically designated to be used for FTR activity in a specific customer account. Any such credit so set aside shall not be considered available to satisfy any other credit requirement the FTR Participant may have with PJMSettlement.

FTR Credit Requirement:

"FTR Credit Requirement" shall mean the amount of credit that a Participant must provide in order to support the FTR positions that it holds and/or for which it is bidding. The FTR Credit Requirement shall not include months for which the invoicing has already been completed, provided that PJMSettlement shall have up to two Business Days following the date of the invoice completion to make such adjustments in its credit systems. FTR Credit Requirements are calculated and applied separately for each separate customer account.

FTR Flow Undiversified:

"FTR Flow Undiversified" shall have the meaning established in Tariff, Attachment Q, section VI.C.6.

FTR Historical Value:

For each FTR for each month, "FTR Historical Value" shall mean the weighted average of historical values over three years for the FTR path using the following weightings: 50% - most recent year; 30% - second year; 20% - third year.

FTR Holder:

"FTR Holder" shall mean the PJM Member that has acquired and possesses an FTR.

FTR Monthly Credit Requirement Contribution:

For each FTR, for each month, "FTR Monthly Credit Requirement Contribution" shall mean the total FTR cost for the month, prorated on a daily basis, less the FTR Historical Value for the month. For cleared FTRs, this contribution may be negative; prior to clearing, FTRs with negative contribution shall be deemed to have zero contribution.

FTR Net Activity:

"FTR Net Activity" shall mean the aggregate net value of the billing line items for auction revenue rights credits, FTR auction charges, FTR auction credits, and FTR congestion credits, and shall also include day-ahead and balancing/real-time congestion charges up to a maximum

net value of the sum of the foregoing auction revenue rights credits, FTR auction charges, FTR auction credits and FTR congestion credits.

FTR Participant:

"FTR Participant" shall mean any Market Participant that provides or is required to provide Collateral in order to participate in PJM's FTR market.

FTR Portfolio Auction Value:

"FTR Portfolio Auction Value" shall mean for each customer account of a Market Participant, the sum, calculated on a monthly basis, across all FTRs, of the FTR price times the FTR volume in MW.

Fuel Cost Policy:

"Fuel Cost Policy" shall mean the document provided by a Market Seller to PJM and the Market Monitoring Unit in accordance with PJM Manual 15 and Operating Agreement, Schedule 2, which documents the Market Seller's method used to price fuel for calculation of the Market Seller's cost-based offers for a generation resource.

Full Notice to Proceed:

"Full Notice to Proceed" shall mean that all material third party contractors have been given the notice to proceed with construction by the Capacity Market Seller or its agent, with a guaranteed completion date backed by liquidated damages.

Definitions – T – U - V

Tangible Net Worth:

"Tangible Net Worth" shall mean total assets less goodwill and other intangible assets, minus total liabilities.

Target Allocation:

"Target Allocation" shall mean the allocation of Transmission Congestion Credits as set forth in Operating Agreement, Schedule 1, section 5.2.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.3, or the allocation of Auction Revenue Rights Credits as set forth in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Third Incremental Auction:

"Third Incremental Auction" shall mean an Incremental Auction conducted three months before the Delivery Year to which it relates.

Third-Party Sale:

"Third-Party Sale" shall mean any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service but not including a sale of energy through the PJM Interchange Energy Market established under the PJM Operating Agreement.

Tie Line:

"Tie Line" shall mean a circuit connecting two balancing authority areas, Control Areas or fully metered electric system regions. Tie Lines may be classified as external or internal as set forth in the PJM Manuals.

Total Lost Opportunity Cost Offer:

"Total Lost Opportunity Cost Offer" shall mean the applicable offer used to calculate lost opportunity cost credits. For pool-scheduled resources specified in PJM Operating Agreement, Schedule 1, section 3.2.3(f-1), and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-1), the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the greater of the Committed Offer or last Real-Time Offer submitted for the offer on which the resource was committed in the Day-ahead Energy Market for each hour in an Operating Day. For all other pool-scheduled resources, the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the offer curve associated with the greater of the Committed Offer or Final Offer for each hour in an Operating Day. For self-scheduled generation resources, the Total Lost

Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, where for self-scheduled generation resources (a) operating pursuant to a cost-based offer, the applicable offer curve shall be the greater of the originally submitted cost-based offer or the cost-based offer that the resource was dispatched on in real-time; or (b) operating pursuant to a market-based offer, the applicable offer curve shall be determined in accordance with the following process: (1) select the greater of the cost-based day-ahead offer and updated cost-based Real-time Offer; (2) for resources with multiple cost-based offers, first, for each cost-based offer select the greater of the day-ahead offer and updated Real-time Offer, and then select the lesser of the resulting cost-based offers; and (3) compare the offer selected in (1), or for resources with multiple cost-based offers the offer selected in (2), with the market-based day-ahead offer and the market-based Real-time Offer and select the highest offer.

Total Net Obligation:

"Total Net Obligation" shall mean all unpaid billed Net Obligations plus any unbilled Net Obligation incurred to date, as determined by PJMSettlement on a daily basis, plus any other Obligations owed to PJMSettlement at the time.

Total Net Sell Position:

"Total Net Sell Position" shall mean all unpaid billed Net Sell Positions plus any unbilled Net Sell Positions accrued to date, as determined by PJMSettlement on a daily basis.

Tracking Ramp Limited Desired

"Tracking Ramp Limited Desired" shall mean the desired MW or MWh calculated pursuant to Tariff, Attachment K-Appendix, section 3.2.3(e-1) and parallel provisions in Operating Agreement, Schedule 1, section 3.2.3(e-1).

Trade Reference:

"Trade Reference" shall mean a reference from a contact or firm that had or has a material business relationship with a Participant.

Transmission Congestion Charge:

"Transmission Congestion Charge" shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses which shall be calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.1 and the parallel provisions of Tariff, Attachment K-Appendix, section 5.1.

Transmission Congestion Credit:

"Transmission Congestion Credit" shall mean the allocated share of total Transmission Congestion Charges credited to each FTR Holder, calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.2, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.

Transmission Constraint Penalty Factor:

"Transmission Constraint Penalty Factor" shall mean the maximum cost of the re-dispatch incurred to control the flows across a transmission constraint and establishes the maximum limit on the Marginal Value.

Transmission Customer:

"Transmission Customer" shall mean any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission a proposed unexecuted Service Agreement, to receive transmission service under Tariff, Part II. This term is used in Tariff, Part I and Tariff, Part VI to include customers receiving transmission service under Tariff, Part II and Tariff, Part III.

Where used in Tariff, Attachment K-Appendix and the parallel provisions of Operating Agreement, Schedule 1, Transmission Customer shall mean an entity using Point-to-Point Transmission Service.

Transmission Facilities:

"Transmission Facilities" shall have the meaning set forth in the Operating Agreement.

Transmission Forced Outage:

"Transmission Forced Outage" shall mean an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the PJM Manuals. A removal from service of a transmission facility at the request of the Office of the Interconnection to improve transmission capability shall not constitute a Forced Transmission Outage.

Transmission Injection Rights:

"Transmission Injection Rights" shall mean Capacity Transmission Injection Rights and Energy Transmission Injection Rights.

Transmission Interconnection Customer:

"Transmission Interconnection Customer" shall mean an entity that submits an Interconnection Request to interconnect or add Merchant Transmission Facilities to the Transmission System or to increase the capacity of Merchant Transmission Facilities interconnected with the

Transmission System in the PJM Region or an entity that submits an Upgrade Request for Merchant Network Upgrades (including accelerating the construction of any transmission enhancement or expansion, other than Merchant Transmission Facilities, that is included in the Regional Transmission Expansion Plan prepared pursuant to Operating Agreement, Schedule 6).

Transmission Interconnection Facilities Study:

"Transmission Interconnection Facilities Study" shall mean a Facilities Study related to a Transmission Interconnection Request.

Transmission Interconnection Feasibility Study:

"Transmission Interconnection Feasibility Study" shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part IV, section 36.2.

Transmission Interconnection Request:

"Transmission Interconnection Request" shall mean a request by a Transmission Interconnection Customer pursuant to Tariff, Part IV to interconnect or add Merchant Transmission Facilities to the Transmission System or to increase the capacity of existing Merchant Transmission Facilities interconnected with the Transmission System in the PJM Region.

Transmission Loading Relief:

"Transmission Loading Relief" shall mean NERC's procedures for preventing operating security limit violations, as implemented by PJM as the security coordinator responsible for maintaining transmission security for the PJM Region.

Transmission Loss Charge:

"Transmission Loss Charge" shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Operating Agreement, Schedule 1, section 5, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.

Transmission Owner:

"Transmission Owner" shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

Transmission Owner Attachment Facilities:

"Transmission Owner Attachment Facilities" shall mean that portion of the Transmission Owner Interconnection Facilities comprised of all Attachment Facilities on the Interconnected Transmission Owner's side of the Point of Interconnection.

Transmission Owner Interconnection Facilities:

"Transmission Owner Interconnection Facilities" shall mean all Interconnection Facilities that are not Customer Interconnection Facilities and that, after the transfer under Tariff, Attachment P, Appendix 2, section 5.5 to the Interconnected Transmission Owner of title to any Transmission Owner Interconnection Facilities that the Interconnection Customer constructed, are owned, controlled, operated and maintained by the Interconnected Transmission Owner on the Interconnected Transmission Owner's side of the Point of Interconnection identified in appendices to the Interconnection Service Agreement and to the Interconnection Construction Service Agreement, including any modifications, additions or upgrades made to such facilities and equipment, that are necessary to physically and electrically interconnect the Customer Facility with the Transmission System or interconnected distribution facilities.

Transmission Owner Upgrade:

"Transmission Owner Upgrade" shall have the same meaning provided in the Operating Agreement.

Transmission Planned Outage:

"Transmission Planned Outage" shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in Operating Agreement, Schedule 1, and the parallel provisions of Tariff, Attachment K-Appendix or the PJM Manuals.

Transmission Provider:

The "Transmission Provider" shall be the Office of the Interconnection for all purposes, provided that the Transmission Owners will have the responsibility for the following specified activities:

(a) The Office of the Interconnection shall direct the operation and coordinate the maintenance of the Transmission System, except that the Transmission Owners will continue to direct the operation and maintenance of those transmission facilities that are not listed in the PJM Designated Facilities List contained in the PJM Manual on Transmission Operations;

(b) Each Transmission Owner shall physically operate and maintain all of the facilities that it owns; and

(c) When studies conducted by the Office of the Interconnection indicate that enhancements or modifications to the Transmission System are necessary, the Transmission Owners shall have the responsibility, in accordance with the applicable terms of the Tariff, Operating Agreement

and/or the Consolidated Transmission Owners Agreement to construct, own, and finance the needed facilities or enhancements or modifications to facilities.

Transmission Provider's Monthly Transmission System Peak:

"Transmission Provider's Monthly Transmission System Peak" shall mean the maximum firm usage of the Transmission Provider's Transmission System in a calendar month.

Transmission Service:

"Transmission Service" shall mean Point-To-Point Transmission Service provided under Tariff, Part II on a firm and non-firm basis.

Transmission Service Request:

"Transmission Service Request" shall mean a request for Firm Point-To-Point Transmission Service or a request for Network Integration Transmission Service.

Transmission System:

"Transmission System" shall mean the facilities controlled or operated by the Transmission Provider within the PJM Region that are used to provide transmission service under Tariff, Part II and Part III.

Transmission Withdrawal Rights:

"Transmission Withdrawal Rights" shall mean Firm Transmission Withdrawal Rights and Non-Firm Transmission Withdrawal Rights.

Turn Down Ratio:

"Turn Down Ratio" shall mean the ratio of a generating unit's economic maximum megawatts to its economic minimum megawatts.

Unconstrained LDA Group:

"Unconstrained LDA Group" shall mean a combined group of LDAs that form an electrically contiguous area and for which a separate Variable Resource Requirement Curve has not been established under Tariff, Attachment DD, section 5.10. Any LDA for which a separate Variable Resource Requirement Curve has not been established under Tariff, Attachment DD, section 5.10 shall be combined with all other such LDAs that form an electrically contiguous area.

Unforced Capacity:

"Unforced Capacity" shall have the meaning specified in the Reliability Assurance Agreement.

Unsecured Credit:

"Unsecured Credit" shall mean any credit granted by PJMSettlement to a Participant that is not secured by Collateral.

Unsecured Credit Allowance:

"Unsecured Credit Allowance" shall mean Unsecured Credit extended by PJMSettlement in an amount determined by PJMSettlement's evaluation of the creditworthiness of a Participant. This is also defined as the amount of credit that a Participant qualifies for based on the strength of its own financial condition without having to provide Collateral. See also: "Working Credit Limit."

Updated VRR Curve:

"Updated VRR Curve" shall mean the Variable Resource Requirement Curve for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect any change in the Reliability Requirement from the Base Residual Auction to such Incremental Auction.

Updated VRR Curve Decrement:

"Updated VRR Curve Decrement" shall mean the portion of the Updated VRR Curve to the left of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year and adjusted, if applicable, by a change in Unforced Capacity commitments associated with Tariff, Attachment DD, section 5.5A(c)(i)(B), and RAA, Schedule 6, section L.9.

Updated VRR Curve Increment:

"Updated VRR Curve Increment" shall mean the portion of the Updated VRR Curve to the right of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year and adjusted, if applicable, by a change in Unforced Capacity commitments associated with Tariff, Attachment DD, section 5.5A(c)(i)(B), and RAA, Schedule 6, section L.9.

Upgrade Construction Service Agreement:

"Upgrade Construction Service Agreement" shall mean that agreement entered into by an Eligible Customer, Upgrade Customer or Interconnection Customer proposing Merchant Network Upgrades, a Transmission Owner, and the Transmission Provider, pursuant to Tariff, Part VI, Subpart B, and in the form set forth in Tariff, Attachment GG.

Upgrade Customer:

"Upgrade Customer" shall mean a customer that submits an Upgrade Request pursuant to Operating Agreement, Schedule 1, section 7.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.8.

Upgrade Feasibility Study:

"Upgrade Feasibility Study" shall mean a study conducted by the Transmission Provider in accordance with Tariff, Part IV, section 36.3.

Upgrade-Related Rights:

"Upgrade-Related Rights" shall mean Incremental Auction Revenue Rights, Incremental Available Transfer Capability Revenue Rights, Incremental Deliverability Rights, and Incremental Capacity Transfer Rights.

Upgrade Request:

"Upgrade Request" shall mean a request submitted in the form prescribed in Tariff, Attachment EE, for evaluation by the Transmission Provider of the feasibility and estimated costs of (a) a Merchant Network Upgrade or (b) the Customer-Funded Upgrades that would be needed to provide Incremental Auction Revenue Rights specified in a request pursuant to Operating Agreement, Schedule 1, section 7.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.8.

Up-to Congestion Counterflow Transaction:

"Up-to Congestion Counterflow Transaction" shall mean an Up-to Congestion Transaction will be deemed an Up-to Congestion Counterflow Transaction if the following value is negative: (a) when bidding, the lower of the bid price and the prior Up-to Congestion Historical Month's average real-time value for the transaction; or (b) for cleared Virtual Transactions, the cleared day-ahead price of the Virtual Transactions.

Up-to Congestion Historical Month:

"Up-to Congestion Historical Month" shall mean a consistently-defined historical period nominally one month long that is as close to a calendar month as PJM determines is practical.

Up-to Congestion Prevailing Flow Transaction:

An Up-to Congestion Transaction shall mean an "Up-to Congestion Prevailing Flow Transaction" if it is not an Up-to Congestion Counterflow Transaction.

Up-to Congestion Reference Price:

"Up-to Congestion Reference Price" for an Up-to Congestion Transaction, shall be the specified percentile price differential between source and sink (defined as sink price minus source price) for real-time prices experienced over the prior Up-to Congestion Historical Month, averaged with the same percentile value calculated for the second prior Up-to Congestion Historical

Month. Up-to Congestion Reference Prices shall be calculated using the following historical percentiles:

For Up-to Congestion Prevailing Flow Transactions: 30th percentile
For Up-to Congestion Counterflow Transactions when bid: 20th percentile
For Up-to Congestion Counterflow Transactions when cleared: 5th percentile

Up-to Congestion Transaction:

"Up-to Congestion Transaction" shall have the meaning specified in Operating Agreement, Schedule 1, section 1.10.1A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.10.1A.

Variable Loads:

"Variable Loads" shall have the meaning specified in Operating Agreement, Schedule 1, section 1.5A.6, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.6.

Variable Resource Requirement Curve:

"Variable Resource Requirement Curve" shall mean a series of maximum prices that can be cleared in a Base Residual Auction for Unforced Capacity, corresponding to a series of varying resource requirements based on varying installed reserve margins, as determined by the Office of the Interconnection for the PJM Region and for certain Locational Deliverability Areas in accordance with the methodology provided in Tariff, Attachment DD, section 5.

Virtual Credit Exposure:
"Virtual Credit Exposure" shall mean the amount of potential credit exposure created by a market participant's bid submitted into the Day-ahead market, as defined in Tariff, Attachment Q.

Virtual Transaction:

"Virtual Transaction" shall mean a Decrement Bid, Increment Offer and/or Up-to Congestion Transaction.

Virtual Transaction Screening:

"Virtual Transaction Screening" shall be the process of reviewing the Virtual Credit Exposure of submitted Virtual Transactions against the Credit Available for Virtual Transactions. If the credit required is greater than credit available, then the Virtual Transactions will not be accepted.

Virtual Transactions Net Activity:

"Virtual Transactions Net Activity" shall mean the aggregate net total, resulting from Virtual Transactions, of (i) Spot Market Energy charges, (ii) Transmission Congestion Charges, and (iii) Transmission Loss Charges, calculated as set forth in Tariff, Attachment K-Appendix, and the

parallel provisions of Operating Agreement, Schedule 1. Virtual Transactions Net Activity may be positive or negative.

Voltage Reduction Action:

"Voltage Reduction Action" shall mean a notification during capacity deficient conditions in which PJM notifies Members to reduce voltage on the distribution system in order to reduce demand and therefore provide a sufficient amount of reserves, maintain tie flow schedules and preserve limited energy sources.

Voltage Reduction Alert:

"Voltage Reduction Alert" shall mean a notification from PJM to alert Members that a voltage reduction may be required during a future critical period.

Voltage Reduction Warning:

"Voltage Reduction Warning" shall mean a notification from PJM to warn Members that PJM's available Synchronized Reserve is less than the Synchronized Reserve Requirement and that present operations have deteriorated such that a voltage reduction may be required.

1.10 Scheduling.

1.10.1 General.

(a) The Office of the Interconnection shall administer scheduling processes to implement a Day-ahead Energy Market and a Real-time Energy Market. PJMSettlement shall be the Counterparty to the purchases and sales of energy that clear the Day-ahead Energy Market and the Real-time Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a Generating Market Buyer's self-schedule or self-supply of its generation resources up to that Generating Market Buyer's Equivalent Load.

(b) The Day-ahead Energy Market shall enable Market Participants to purchase and sell energy through the PJM Interchange Energy Market at Day-ahead Prices and enable Transmission Customers to reserve transmission service with Transmission Congestion Charges and Transmission Loss Charges based on locational differences in Day-ahead Prices. Up-to Congestion Transactions submitted in the Day-ahead Energy Market shall not require transmission service and Transmission Customers shall not reserve transmission service for such Up-to Congestion Transactions. Market Participants whose purchases and sales, and Transmission Customers whose transmission uses are scheduled in the Day-ahead Energy Market, shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, at the applicable Day-ahead Prices for the amounts scheduled.

(c) (i) In the Real-time Energy Market, Market Participants that deviate from the amounts of energy purchases or sales scheduled in the Day-ahead Energy Market shall be obligated to purchase or sell energy for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(ii) In the Real-time Energy Market, Transmission Customers that deviate from the transmission uses, scheduled in the Day-ahead Energy Market shall be obligated to pay Transmission Congestion Charges and Transmission Loss Charges for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(iii) Market Participants that deviate in real-time from the amounts of Secondary Reserve, Non-Synchronized Reserve, or Synchronized Reserve sales, scheduled day-ahead shall be obligated to purchase Secondary Reserve, Non-Synchronized Reserve, or Synchronized Reserve for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of

conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling does not encompass Coordinated External Transactions, which are subject to the procedures of Tariff, Attachment K-Appendix, section 1.13. Scheduling shall be conducted as specified in section 1.10.1A below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM Manuals. Such resources committed by the Office of the Interconnection to alleviate or mitigate an Emergency will not receive energy uplift Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Tariff, Attachment K-Appendix, section 3.2.3 and Tariff, Attachment K-Appendix, section 6.6.

(e) To the extent that Tariff, Attachment K-Appendix, sections 3.2.3A, 3.2.3A.001, and 3.2.3A.01 and the parallel provision of Operating Agreement, Schedule 1, sections 3.2.3A, 3.2.3A.001, and 3.2.3A.01 does not meet the Minimum Synchronized Reserve Requirement, the Minimum Primary Reserve Requirement, and the Minimum 30-minute Reserve Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Tariff, Attachment K-Appendix, section 1.7.17 and the parallel provision of Operating Agreement, Schedule 1, section 1.7.17, and Tariff, Attachment K-Appendix, section 1.10 and the parallel provision of Operating Agreement, Schedule 1, section 1.10. In addition, the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the day-ahead market.

1.10.1A Day-ahead and Real-time Energy Market Scheduling.

The following actions shall occur not later than 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the Office of the Interconnection in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Schedule.

(a) Each Market Participant may submit to the Office of the Interconnection specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the PJM Manuals. Each Market Buyer shall inform the Office of the Interconnection of the prices, if any, at which it desires not to include its load in the Day-ahead Energy Market rather than pay the Day-ahead Price. PRD Providers that have committed Price Responsive Demand in accordance with the Reliability Assurance Agreement shall submit to the Office of the Interconnection, in accordance with procedures specified in the PJM Manuals, any desired updates to their previously submitted PRD Curves, provided that such updates are consistent with their Price Responsive Demand

commitments, and provided further that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue may only submit PRD Curves for the Real-time Energy Market. Price Responsive Demand that has been committed in accordance with the Reliability Assurance Agreement shall be presumed available for the next Operating Day in accordance with the most recently submitted PRD Curve unless the PRD Curve is updated to indicate otherwise. PRD Providers may also submit PRD Curves for any Price Responsive Demand that is not committed in accordance with the Reliability Assurance Agreement; provided that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue may only submit PRD Curves for the Real-time Energy Market. All PRD Curves shall be on a PRD Substation basis, and shall specify the maximum time period required to implement load reductions.

(b) Each Generating Market Buyer shall submit to the Office of the Interconnection: (i) hourly schedules for resource increments, including hydropower units, self-scheduled by the Market Buyer to meet its Equivalent Load; and (ii) the Dispatch Rate at which each such self-scheduled resource will disconnect or reduce output, or confirmation of the Market Buyer's intent not to reduce output.

(c) All Market Participants shall submit to the Office of the Interconnection schedules for any energy exports, energy imports, and wheel through transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection if the transaction is to be scheduled in the Day-ahead Energy Market. Any Market Participant that elects to schedule an export, import or wheel through transaction in the Day-ahead Energy Market may specify the price (such price not to exceed $2,000/MWh), if any, at which the export, import or wheel through transaction will be wholly or partially curtailed. The foregoing price specification shall apply to the applicable interface pricing point. Any Market Participant that elects not to schedule its export, import or wheel through transaction in the Day-ahead Energy Market shall inform the Office of the Interconnection if the parties to the transaction are not willing to incur Transmission Congestion and Loss Charges in the Real-time Energy Market in order to complete any such scheduled transaction. Such transactions in the Real-time Energy Market, other than Coordinated Transaction Schedules and emergency energy sales and purchases, may specify a price up to $2,000/MWh. Scheduling of such transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

i) Market Participants shall submit schedules for all energy purchases for delivery within the PJM Region, whether from resources inside or outside the PJM Region;

ii) Market Participants shall submit schedules for exports for delivery outside the PJM Region from resources within the PJM Region that are not Dynamic Transfers to such entities pursuant to Tariff, Attachment K-Appendix, section 1.12; and

iii) In addition to the foregoing schedules for exports, imports and wheel through transactions, Market Participants shall submit confirmations of each scheduled

transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(c-1) A Market Participant may elect to submit in the Day-ahead Energy Market a form of Virtual Transaction that combines an offer to sell energy at a source, with a bid to buy the same megawatt quantity of energy at a sink where such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink. The Office of Interconnection will schedule these transactions only to the extent this difference in Locational Marginal Prices is within the maximum amount specified by the Market Participant. A Virtual Transaction of this type is referred to as an "Up-to Congestion Transaction." Such Up-to Congestion Transactions may be wholly or partially scheduled depending on the price difference between the source and sink locations in the Day-ahead Energy Market. The maximum difference between the source and sink prices that a participant may specify shall be limited to +/- $50/MWh. The foregoing price specification shall apply to the price difference between the specified source and sink in the day-ahead scheduling process only. An accepted Up-to Congestion Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-ahead Energy Market.

(c–2) A Market Participant may elect to submit an Increment Offer and/or Decrement Bid form of Virtual Transaction in the Day-ahead Energy Market and shall specify the price for such transaction which shall be limited to $2,000/megawatt-hour.

(c-3) Up-to Congestion Transactions may only be submitted at hubs, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b). Increment Offers and Decrement Bids may be only submitted at hubs, nodes at which physical generation or load is settled, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b).

(d) Market Sellers in the Day-ahead Energy Market shall submit offers for the supply of energy, demand reductions, or other services for the following Operating Day for each clock hour for which the Market Seller desires or is required to make its resource available to the Office of the Interconnection. Offers for the supply of energy may be cost-based, market-based, or both, and may vary hourly. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, Operating Agreement, Schedule 2, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that is committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. Such offers shall be based on the ICAP equivalent of the Market Seller's cleared UCAP capacity commitment, provided, however, (i) where the underlying resource is a Capacity Storage Resource, with the exception of Capacity Storage Resource participating in the Energy Storage Resource Participation Model, or an Intermittent Resource, the Market Seller shall satisfy the must offer requirement by either self-scheduling or offering the unit as a dispatchable

resource, in accordance with the PJM Manuals, where the hourly day-ahead self-scheduled values for such Capacity Storage Resources and Intermittent Resources may vary hour to hour from the capacity commitment, and (ii) where the underlying resource is a Hybrid Resource or Capacity Storage Resource participating in the Energy Storage Resource Participation Model, the Market Seller shall satisfy the must offer requirement by self-scheduling the unit in accordance with the PJM Manuals, where the hourly day-ahead self-scheduled values for such Hybrid Resource or Capacity Storage Resource may vary hour to hour from the capacity commitment. Any offer not designated as a Maximum Emergency offer shall be considered available for scheduling and dispatch under both Emergency and non-Emergency conditions. Offers may only be designated as Maximum Emergency offers to the extent that the Generation Capacity Resource falls into at least one of the following categories:

i) Environmental limits. If the resource has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited to operating only during declared PJM capacity emergencies by a governmental authority.

ii) Fuel limits. If physical events beyond the control of the resource owner result in the temporary interruption of fuel supply and there is limited on-site fuel storage. A fuel supplier's exercise of a contractual right to interrupt supply or delivery under an interruptible service agreement shall not qualify as an event beyond the control of the resource owner.

iii) Temporary emergency conditions at the unit. If temporary emergency physical conditions at the resource significantly limit its availability.

iv) Temporary megawatt additions. If a resource can provide additional megawatts on a temporary basis by oil topping, boiler over-pressure, or similar techniques, and such megawatts are not ordinarily otherwise available.

The submission of offers for resource increments that are not committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1 shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2, and the PJM Manuals, as applicable. Energy offered from generation resources that are not committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1 shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region.

The foregoing offers:

i) Shall specify the Generation Capacity Resource or Economic Load Response Participant resource and energy or demand reduction amount, respectively, for each clock hour in the offer period;

ii) Shall specify the amounts and prices for each clock hour during the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;

iii) May specify for generation resources offer parameters for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) Minimum Run Time; (2) maximum run time; (3) Start-up Costs; (4) No-load Costs; (5) Incremental Energy Offer; (6) notification time; (7) availability; (8) ramp rate; (9) Economic Minimum; (10) Economic Maximum; (11) emergency minimum MW; (12) emergency maximum MW; (13) Synchronized Reserve maximum MW; (14) Secondary Reserve maximum MW; and (15) condense to generation time constraints, and may specify offer parameters for Economic Load Response Participant resources for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) minimum down time; (2) maximum down time; (3) minimum release time; (4) shutdown costs; (5) Incremental Energy Offer; (6) notification time; (7) Economic Minimum; and (8) Economic Maximum;

iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;

v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with additional schedules applicable if accepted after the foregoing deadline;

vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer for the clock hour, which offer shall remain open through the Operating Day, for which the offer is submitted, unless the Market Seller a) submits a Real-time Offer for the applicable clock hour, or b) updates the availability of its offer for that hour, as further described in the PJM Manuals;

vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day, unless modified after the close of the Day-ahead Energy Market as permitted pursuant to sections 1.10.9A or 1.10.9B below;

viii) Shall not exceed an energy offer price of $1,000/megawatt-hour for all generation resources, except (1) when a Market Seller's cost-based offer is above $1,000/megawatt-hour and less than or equal to $2,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer; and (2) when a Market Seller's cost-based offer is greater than $2,000/megawatt-hour, then its market-based offer must be less than or equal to $2,000/megawatt-hour;

ix) Shall not exceed a demand reduction offer price of $1,000/megawatt-hour, except when an Economic Load Response Participant submits a cost-based offer that includes an incremental cost component that is above $1,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer but in no event greater than $2,000/megawatt-hour;

x) Shall not exceed an offer price as follows for Emergency Load Response and Pre-Emergency Load Response participants with:

a) a 30 minute lead time, pursuant to Tariff, Attachment DD-1, section A.2 and the parallel provision of RAA, Schedule 6, $1,000/megawatt-hour, plus the applicable Reserve Penalty Factor for the Primary Reserve Requirement, minus $1.00;

b) an approved 60 minute lead time, pursuant to Tariff, Attachment DD-1, section A.2 and the parallel provision of RAA, Schedule 6, $1,000/megawatt hour, plus [the applicable Reserve Penalty Factor for the Primary Reserve Requirement divided by 2]; and

c) an approved 120 minute lead time, pursuant to Tariff, Attachment DD-1, section A.2 and the parallel provisions of RAA, Schedule 6, $1,100/megawatt-hour; and

xi) Shall not exceed an energy offer price of $0.00/MWh for pumped storage hydropower units scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation for each 30 minute Regulation clearing interval for which the Market Seller desires to make its resource available to the Office of the Interconnection to provide Regulation that shall specify the megawatts of Regulation being offered, which must equal or exceed 0.1 megawatts, in the Regulation Zone for which such Regulation is offered, the price of the capability offer in dollars per MW, the price of the mileage offer in Dollars per change in MW, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the resource's opportunity costs. Such offers may vary for each 30 minute Regulation clearing interval, and may be updated each 30 minute Regulation clearing interval, up to 35 minutes before the applicable 30 minute Regulation clearing interval during the Operating Day. The total of the mileage offer multiplied by the historical average mileage used in the market clearing plus the capability offer shall not exceed $100/megawatt-hour. In addition to any market-based offer for Regulation, the Market Seller also shall submit a cost-based offer. A cost-based offer must be in the form specified in the PJM Manuals and consist of the following components as well as any other components specified in the PJM Manuals:

i. The costs (in $/MW) of the fuel cost increase due to the steady-state heat rate increase resulting from operating the unit at lower megawatt output incurred from the provision of Regulation shall apply to the capability offer;

ii. The cost increase (in $/ΔMW) in costs associated with movement of the regulation resource incurred from the provision of Regulation shall apply to the mileage offer; and

a. Only Regulation-only resources may include all variable operation and maintenance expenses in the mileage offer, as defined in the PJM Manuals.

iii. An adder of up to $12.00 per megawatt of Regulation provided applied to the capability offer.

Qualified Regulation capability must satisfy the measurement and verification tests specified in the PJM Manuals.

(f) Each Market Seller owning or controlling the output of a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative shall submit a forecast of the availability of each such Generation Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with Start-up Costs and No-load Costs, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours. Such resources committed by the Office of the Interconnection will not receive energy uplift Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Tariff, Attachment K-Appendix, section 3.2.3 and Tariff, Attachment K-Appendix, section 6.6.

(g) Each component of an offer by a Market Seller of a Generation Capacity Resource that is constant for the entire Operating Day and does not vary hour to hour shall remain in effect for subsequent Operating Days until superseded or canceled.

(h) The Office of the Interconnection shall post the total hourly loads scheduled in the Day-ahead Energy Market, as well as, its estimate of the combined hourly load of the Market Buyers for the next four days, and peak load forecasts for an additional three days.

(i) Except for Economic Load Response Participants, all Market Participants may submit Virtual Transactions that apply to the Day-ahead Energy Market only. Such Virtual Transactions must comply with the requirements set forth in the PJM Manuals and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-ahead Energy Market. The Office of the Interconnection may require that a market participant shall not submit in excess of a defined number of bid/offer segments in the Day-ahead Energy Market, as specified in the PJM Manuals, when the Office of the

Interconnection determines that such limit is required to avoid or mitigate significant system performance problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to 10:00 a.m. EPT on the day that the Day-ahead Energy Market will clear. For purposes of this provision, a bid/offer segment is each pairing of price and megawatt quantity submitted as part of an Increment Offer or Decrement Bid. For purposes of applying this provision to an Up-to Congestion Transaction, a bid/offer segment shall refer to the pairing of a source and sink designation, as well as price and megawatt quantity, that comprise each Up-to Congestion Transaction.

(j) (i) Offers to Supply Synchronized and Non-Synchronized Reserves By Generation Resources in the Day-ahead and Real-time Reserve Markets

(1) Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Tariff, Attachment DD, is capable of providing Synchronized Reserve or Non-Synchronized Reserve as specified in section 1.7.19A(a), in section 1.7.19A.01(a) and in the PJM Manuals, and has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage, shall submit offers or otherwise make their 10-minute reserve capability available to supply Synchronized Reserve or, as applicable, Non-Synchronized Reserve, including any portion that is self-scheduled by the Generating Market Buyer, in an amount equal to the available 10-minute reserve capability of such Generation Capacity Resource. Market Sellers of Generation Capacity Resources subject to this must-offer requirement that do not make the reserve capability of such resources available when such resource is able to operate with a dispatchable range (e.g. through offering a fixed output) will be in violation of this provision.

(2) Market Sellers of all other generation resources that (A) are capable of providing Synchronized Reserve or Non-Synchronized Reserve, as specified in section 1.7.19A(a), in section 1.7.19A.01(a) and in the PJM Manuals, (B) are located within the metered boundaries of the PJM Region, and (C) have submitted offers for the supply of energy into the Day-ahead Energy Market and/or Real-time Energy Market shall be deemed to have made their reserve capability available to provide Synchronized Reserve or Non-Synchronized Reserve in the Day-ahead Energy Market and/or Real-time Energy Market for each clock hour for which the Market Seller submits an available offer to supply energy; provided, however that hydroelectric generation resources and Energy Storage Resources are not automatically deemed available to provide reserves based on the submission of an available energy offer but may submit offers to supply Synchronized Reserve and Non-Synchronized Reserve, as applicable.

(3) Offers for the supply of Synchronized Reserve by all generation resources must be cost-based. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65

minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A, section 1.10.9B below, and the PJM Manuals, as applicable. For offers to supply Synchronized Reserve, the offer price shall not exceed the expected value of the penalty for failing to provide Synchronized Reserve, where such expected value shall be recalculated annually, in accordance with the PJM Manuals, and posted on PJM's website. The expected value of the penalty is calculated as the product of: (A) the average penalty, expressed in $/MWh, multiplied by (B) the average rate of non-performance during Synchronized Reserve events multiplied by (C) the probability a Synchronized Reserve event that will qualify for non-performance assessments will occur.

The expected value of the penalty shall be determined by an annual review of the twelve-month period ending October 31 of the calendar year in which the review is performed. The Office of the Interconnection shall post the results of its annual review by no later than December 15, and the revised offer price cap shall be effective as of the following January 1; provided, however, that at the time of implementation of this rule the expected value of the penalty shall be $0.02/MWh, and for the period from the second month after implementation through the second December 31 following such date of implementation, the expected value of the penalty shall be recalculated on a monthly basis using data from the implementation date of this rule through the 15th day of the current month, and the revised value shall be effective the 1st day of the following month.

(4) All Non-Synchronized Reserve offers shall be for $0.00/MWh. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this subsection (d) of this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

(ii) Determination of Available Synchronized Reserve Capability of Generation Resources

(1) For each offer to supply reserves by a synchronized resource, the Office of the Interconnection shall determine the MW of available Synchronized Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market, in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Hydroelectric generation resources and Energy Storage Resources may submit offers for their available Synchronized Reserve capability as part of their offer into the Synchronized Reserve market,

provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(j)(i) above must submit a Synchronized Reserve offer which specifies the MW of available Synchronized Reserve capability in order to remain compliant with such requirements.

(2) An on-line generation resource's available Synchronized Reserve capability, except for generation resources capable of synchronous condensing, shall be determined in accordance with the PJM Manuals and based on the resource's current performance and initial energy output and the following offer parameters submitted as part of the resource's energy offer: (A) ramp rate; (B) Economic Minimum; and (C) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Synchronized Reserves above the Synchronized Reserve maximum MW.

For generation resources capable of synchronous condensing, the resource's available Synchronized Reserve capability shall be based on the following offer parameters submitted as part of the resource's energy offer: (D) ramp rate; (E) condense to generation time constraints; (F) Economic Minimum; and (G) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Synchronized Reserves above the Synchronized Reserve maximum MW.

(3) Any Market Seller that believes its generating unit has operating modes, limits, or conditions where the unit would not be capable of providing Synchronized Reserves in real time, can submit to the Office of the Interconnection with a copy to the Market Monitoring Unit a request for an exception from being assigned Synchronized Reserves in the Real-time Synchronized Reserve Market during time periods in which the generating unit is in those operating modes, limits, or conditions. As part of the request, the Market Seller shall supply, for each generating unit, technical information about the operational modes, limits, or conditions to support the requested exception, as further detailed in the PJM Manuals. The Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a request for such an exception. Within 60 days of the submission of the request, the Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, whether the request is approved or denied. The effective

date of any approved request will be provided in the written notification. If a Market Seller has an approved exception, the Market Seller must communicate to the Office of the Interconnection when the unit cannot provides reserves, and the Office of the Interconnection will provide a mechanism for Market Sellers with an approved exception to provide such communication to the Office of the Interconnection in real time, as further detailed in the PJM Manuals. An approved exception will remain applicable to the unit until such time as the Office of the Interconnection determines that a change is needed or the Market Seller notifies the Office of the Interconnection, with a copy to the Market Monitoring Unit, that a change is needed based on changed operational capabilities of the unit. Market Sellers must notify the Office of the Interconnection, with a copy to the Market Monitoring Unit, within 30 days of any changed operational capabilities that necessitate a change in an approved exception.

(iii) Determination of Available Non-Synchronized Reserve Capability of Generation Resources

(1) For each offer to supply reserves by an off-line generation resource, the Office of the Interconnection shall determine the MW of available Non-Synchronized Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Such hydroelectric generation resources or Energy Storage Resources may submit offers for their available Non-Synchronized Reserve capability as part of their offer into the Non-Synchronized Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(j)(i) above must submit a Non-Synchronized Reserve offer which specifies the MW of available Non-Synchronized Reserve capability in order to remain compliant with such requirements.

(2) An off-line generation resource's available Non-Synchronized Reserve capability shall be determined in accordance with the PJM Manuals and based on the following offer parameters submitted as part of the resource's energy offer: (A) startup time; (B) notification time; (C) ramp rate; (D) Economic Minimum; and (E) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Non-Synchronized Reserves above its Synchronized Reserve maximum MW.

(iv) Offers to Supply Synchronized Reserves by Economic Load Response Participant Resources in the Day-ahead and Real-time Reserve Markets

(1) Economic Load Response Participants that submit offers to reduce demand into the Day-ahead Energy Market and Real-time Energy Market and wish to make their resources available to supply Synchronized Reserve may submit offers to supply Synchronized Reserve from such resources, where such offers shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.1 megawatts and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day.

(2) All offers to supply Synchronized Reserve offers from Economic Load Response Participant resources shall not exceed the expected value of the penalty for failing to provide Synchronized Reserve, as determined in accordance with section 1.10.1A(j)(i)(3) above. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

(k) An Economic Load Response Participant that wishes to participate in the Day-ahead Energy Market by reducing demand shall submit an offer to reduce demand to the Office of the Interconnection for each clock hour for which the Economic Load Response Participant desires to make its resource available to the Office of the Interconnection to reduce demand. The offer must equal or exceed 0.1 megawatts, may vary hourly, and shall specify: (i) the amount of the offered curtailment in minimum increments of .1 megawatts: (ii) the Day-ahead Locational Marginal Price above which the end-use customer will reduce load, subject to section 1.10.1A(d)(ix); and (iii) at the Economic Load Response Participant's option, shutdown costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum of number of contiguous hours for which the load reduction must be committed. Such offers may be updated each hour, up to 65 minutes before the applicable clock hour during the Operating Day. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs) per hour.

(l) Market Sellers owning or controlling the output of an Economic Load Response Participant resource that was committed in an FRR Capacity Plan, or that was self-supplied or that offered and cleared in a Base Residual Auction or Incremental Auction, may submit demand reduction bids for the available load reduction capability of the Economic Load Response Participant resource. The submission of demand reduction bids for Economic Load Response Participant resource increments that were not committed in an FRR Capacity Plan, or that have not cleared in a Base Residual Auction or Incremental Auction, shall be optional, but any such bids must contain the information required to be included in such bids, as specified in the PJM Economic Load Response Program. An Economic Load Response Participant resource that was committed in an FRR Capacity Plan, or that was self-supplied or offered and cleared in a Base Residual Auction or Incremental Auction, may submit a demand reduction bid in the Day-ahead Energy Market as specified in the Economic Load Response Program; provided, however, that in

the event of an Emergency PJM shall require Economic Load Response Participant resources to reduce load, notwithstanding that the Zonal LMP at the time such Emergency is declared is below the price identified in the demand reduction bid.

(m) (i) Offers to Supply Secondary Reserve By Generation Resources

(1) Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Tariff, Attachment DD, that is available for energy, is capable of providing Secondary Reserve, as specified in section 1.7.19A.02(a) and in the PJM Manuals, and has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers to supply Secondary Reserve, or otherwise make their Secondary Reserve capability available. Such offers shall be for an amount equal to the resource's available energy output achievable within thirty minutes (less its energy output achievable within ten minutes) from a request of the Office of the Interconnection. Market Sellers of Generation Capacity Resources subject to this must-offer requirement that do not make the reserve capability of such resources available when such resource is able to operate with a dispatchable range (e.g. through offering a fixed output) will be in violation of this provision.

(2) Market Sellers of all other generation resources located within the metered boundaries of the PJM Region that submit offers for the supply of energy into the Day-ahead Energy Market and/or Real-time Energy Market and are capable of providing Secondary Reserve, as specified in the PJM Manuals, shall be deemed to have made their reserve capability available to provide Secondary Reserve in the Day-ahead Energy Market and/or Real-time Energy Market for each clock hour for which the Market Seller submits an available offer to supply energy; provided, however that hydroelectric generation resources and Energy Storage Resources are not automatically deemed available to provide reserves based on the submission of an available energy offer but may submit offers to supply Secondary Reserve, as applicable.

(3) Offers for the supply of Secondary Reserve shall be for $0.00/MWh. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this subsection (d) above, section 1.10.9B below, and the PJM Manuals, as applicable.

(ii) Determination of Available Secondary Reserve Capability of Generation Resources

(1) For each offer to supply Secondary Reserve by a generation resource, the Office of the Interconnection shall determine the MW of available Secondary Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Hydroelectric generation resources or Energy Storage Resources may submit their available Secondary Reserve capability as part of their offer into the Secondary Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(m)(i) above must submit a Secondary Reserve offer which specifies the MW of available Secondary Reserve capability in order to remain compliant with such requirements.

(2) (A) An on-line generation resource's available Secondary Reserve capability, except for generation resources capable of synchronous condensing, shall be based on the resource's current performance and initial energy output, the resource's available Synchronized Reserve capability; and the following offer parameters submitted as part of the energy offer: (i) ramp rate; (ii) Economic Minimum; and (iii) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(B) For generation resources capable of synchronous condensing, the resource's available Secondary Reserve capability shall be based on the following offer parameters submitted as part of the energy offer: (i) ramp rate; (ii) condense to generation time constraints; (iii) Economic Minimum; and (iv) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(C) An off-line generation resource's available Secondary Reserve capability, shall be based on the resource's available Secondary Reserve capability and the following offer parameters submitted as part of the resource's energy offer: (i) startup time; (ii) notification time; (iii)

ramp rate; (iv) Economic Minimum; and (v) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(3) Any Market Seller that believes its generating unit has operating modes, limits, or conditions where the unit would not be capable of providing Secondary Reserves in real time, can submit to the Office of the Interconnection with a copy to the Market Monitoring Unit a request for an exception from being assigned Secondary Reserves in the Real-time Secondary Reserve Market during time periods in which the generating unit is in those operating modes, limits, or conditions. As part of the request, the Market Seller shall supply, for each generating unit, technical information about the operational modes, limits, or conditions to support the requested exception, as further detailed in the PJM Manuals. The Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a request for such an exception. Within 60 days of the submission of the request, the Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, whether the request is approved or denied. The effective date of any approved request will be provided in the written notification. If a Market Seller has an approved exception, the Market Seller must communicate to the Office of the Interconnection when the unit cannot provides reserves, and the Office of the Interconnection will provide a mechanism for Market Sellers with an approved exception to provide such communication to the Office of the Interconnection in real time, as further detailed in the PJM Manuals. An approved exception will remain applicable to the unit until such time as the Office of the Interconnection determines that a change is needed or the Market Seller notifies the Office of the Interconnection, with a copy to the Market Monitoring Unit, that a change is needed based on changed operational capabilities of the unit. Market Sellers must notify the Office of the Interconnection, with a copy to the Market Monitoring Unit, within 30 days of any changed operational capabilities that necessitate a change in an approved exception.

(iii) Offers to Supply Secondary Reserves by Economic Load Response Participant resources

(1) Each Economic Load Response Participant that submits offers to reduce demand into the Day-ahead Energy Market and Real-time Energy Market and wishes to make their resources available to supply Secondary Reserve shall

submit offers to supply Secondary Reserve from such resources, where such offers shall specify the megawatts of Secondary Reserve being offered, which must equal or exceed 0.1 megawatts and include such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day.

(2) All Secondary Reserve offers by Economic Load Response Participant resources shall be for $0.00/MWh. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

(n) A Market Participant may submit a Day-Ahead Pseudo-Tie Transaction for a Market Participant's generator within the PJM balancing authority area that is a Pseudo-Tie into the MISO balancing authority area. Day-Ahead Pseudo-Tie Transactions combine an offer to sell energy at a source with a bid to buy the same megawatt quantity of energy at a sink where such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink.

Each Day-Ahead Pseudo-Tie Transaction shall: (1) source at a Market Participant's generator within the PJM balancing authority area that Pseudo-Ties into MISO; and (2) sink at the PJM-MISO interface. A Market Participant must reserve transmission service in accordance with the PJM Tariff for each Day-Ahead Pseudo-Tie Transaction. Megawatt quantities for Day-Ahead Pseudo-Tie Transactions shall be greater than zero and less than or equal to the transmission service reserved for the Day-Ahead Pseudo-Tie Transaction. An accepted Day-Ahead Pseudo-Tie Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-Ahead Energy Market.

1.10.1B Demand Bid Scheduling and Screening

(a) The Office of the Interconnection shall apply Demand Bid Screening to all Demand Bids submitted in the Day-ahead Energy Market for each Load Serving Entity, separately by Zone. Using Demand Bid Screening, the Office of the Interconnection will automatically reject a Load Serving Entity's Demand Bids in any future Operating Day for which the Load Serving Entity submits bids if the total megawatt volume of such bids would exceed the Load Serving Entity's Demand Bid Limit for any hour in such Operating Day, unless the Office of the Interconnection permits an exception pursuant to subsection (d) below.

(b) On a daily basis, PJM will update and post each Load Serving Entity's Demand Bid Limit in each applicable Zone. Such Demand Bid Limit will apply to all Demand Bids submitted by that Load Serving Entity for each future Operating Day for which it submits bids. The Demand Bid Limit is calculated using the following equation:

Demand Bid Limit = greater of (Zonal Peak Demand Reference Point * 1.3), or (Zonal Peak Demand Reference Point + 10MW)

Where:

1. Zonal Peak Demand Reference Point = for each Zone: the product of (a) LSE Recent Load Share, multiplied by (b) Peak Daily Load Forecast.
2. LSE Recent Load Share is the Load Serving Entity's highest share of Network Load in each Zone for any hour over the most recently available seven Operating Days for which PJM has data.
3. Peak Daily Load Forecast is PJM's highest available peak load forecast for each applicable Zone that is calculated on a daily basis.

(c) A Load Serving Entity whose Demand Bids are rejected as a result of Demand Bid Screening may change its Demand Bids to reduce its total megawatt volume to a level that does not exceed its Demand Bid Limit, and may resubmit them subject to the applicable rules related to bid submission outlined in Tariff, Operating Agreement and PJM Manuals.

(d) PJM may allow a Load Serving Entity to submit bids in excess of its Demand Bid Limit when circumstances exist that will cause, or are reasonably expected to cause, a Load Serving Entity's actual load to exceed its Demand Bid Limit on a given Operating Day. Examples of such circumstances include, but are not limited to, changes in load commitments due to state sponsored auctions, mergers and acquisitions between PJM Members, and sales and divestitures between PJM Members. A Load Serving Entity may submit a written exception request to the Office of Interconnection for a higher Demand Bid Limit for an affected Operating Day. Such request must include a detailed explanation of the circumstances at issue and supporting documentation that justify the Load Serving Entity's expectation that its actual load will exceed its Demand Bid Limit.

1.10.2 Pool-scheduled Resources.

Pool-scheduled resources are those resources for which Market Participants submitted offers to sell energy in the Day-ahead Energy Market and offers to reduce demand in the Day-ahead Energy Market, which the Office of the Interconnection scheduled in the Day-ahead Energy Market as well as generators committed by the Office of the Interconnection subsequent to the Day-ahead Energy Market. Such resources shall be committed to provide energy in the real-time dispatch unless the schedules for such units are revised pursuant to section 1.10.9 below or Tariff, Attachment K-Appendix, section 1.11. Pool-scheduled resources shall be governed by the following principles and procedures.

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, whether the resource is expected to be needed to maintain system reliability during the Operating Day, Start-up Costs, No-load Costs and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in section 1.10.1A above. Hydropower units can only be pool-scheduled if they are pumped storage units and scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

(b) A resource that is scheduled by a Market Participant to support a bilateral sale, or that is self-scheduled by a Generating Market Buyer, shall not be selected by the Office of the Interconnection as a pool-scheduled resource except in an Emergency.

(c) Market Sellers offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the Office of the Interconnection that is sufficient to enable the Office of the Interconnection to determine the available operating hours of such facilities.

(d) The Market Seller of a resource selected as a pool-scheduled resource shall receive payments or credits for energy, demand reductions or related services, or for Start-up Costs and No-load Costs, from the Office of the Interconnection on behalf of the Market Buyers in accordance with Tariff, Attachment K-Appendix, section 3. Alternatively, the Market Seller shall receive, in lieu of Start-up Costs and No-load Costs, its actual costs incurred, if any, up to a cap of the resource's Start-up Costs, if the Office of the Interconnection cancels its selection of the resource as a pool-scheduled resource and so notifies the Market Seller before the resource is synchronized.

(e) Market Participants shall make available their pool-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone.

(f) Economic Load Response Participants offering to reduce demand shall specify: (i) the amount of the offered curtailment, which must equal or exceed 0.1 megawatts, in minimum increments of 0.1 megawatts; (ii) the real-time Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, shut-down costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum number of contiguous hours for which the load reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market and/or the Real-time Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs). Economic Load Response Participants offering to reduce demand shall also indicate the hours that the demand reduction is not available.

1.10.3 Self-scheduled Resources.

Self-scheduled resources shall be governed by the following principles and procedures.

(a) Each Generating Market Buyer shall use all reasonable efforts, consistent with Good Utility Practice, not to self-schedule resources in excess of its Equivalent Load.

(b) The offered prices of resources that are self-scheduled and not dispatchable by the Office of the Interconnection shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.

(c) Market Participants shall make available their self-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone, by submitting an offer as to such resources.

(d) A Market Participant self-scheduling a resource in the Day-ahead Energy Market that does not deliver the energy in the Real-time Energy Market, shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(e) A Market Participant self-scheduling a resource to supply Synchronized Reserve in the Day-ahead Synchronized Reserve Market that does not deliver the scheduled megawatt quantity in the applicable real-time reserve market, shall replace the Synchronized Reserve not delivered and shall pay for such Synchronized Reserve at the applicable Real-time Synchronized Reserve Market Clearing Price. Market Participants shall not self-schedule a resource to provide Secondary Reserve or Non-Synchronized Reserve.

(f) For energy, hydropower units, excluding pumped storage units, may only be self-scheduled.

(g) A resource that has been self-scheduled shall not receive payments or credits for Start-up Costs or No-load Costs.

1.10.4 Capacity Resources.

(a) A Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that is selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection. Such a Generation Capacity Resource that does not deliver energy as scheduled shall be deemed to have experienced a Generator Forced Outage to the extent of such energy not delivered. A Market Participant offering such Generation Capacity Resource in the Day-ahead Energy Market shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Energy from a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that has not been scheduled in the Day-ahead Energy Market may be sold on a bilateral basis by the Market Seller, may be self-scheduled, or may be offered for dispatch during the Operating Day in accordance with the procedures specified in this Schedule. Such a Generation Capacity Resource that has not been scheduled in the Day-ahead Energy Market and that has been sold on a bilateral basis must be made available upon request to the Office of the Interconnection for scheduling and dispatch during the Operating Day if the Office of the Interconnection declares a Maximum Generation Emergency. Any such resource so scheduled and dispatched shall receive the applicable Real-time Price for energy delivered.

1.10.5 External Resources.

(a) External Resources may submit offers to the PJM Interchange Energy Market, in accordance with the day-ahead and real-time scheduling processes specified above. An External Resource selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection, and except as specified below shall be compensated on the same basis as other pool-scheduled resources. External Resources that are not capable of Dynamic Transfer shall, if selected by the Office of the Interconnection on the basis of the Market Seller's Offer Data, be block loaded on an hourly scheduled basis. Market Sellers shall offer External Resources to the PJM Interchange Energy Market on either a resource-specific or an aggregated resource basis. A Market Participant whose pool-scheduled resource does not deliver the energy scheduled in the Day-ahead Energy Market shall replace such energy not delivered as scheduled in the Day-ahead Energy Market with energy from the PJM Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Offers for External Resources from an aggregation of two or more generating units shall so indicate, and shall specify, in accordance with the Offer Data requirements specified by the Office of the Interconnection: (i) energy prices; (ii) hours of energy availability; (iii) a minimum dispatch level; (iv) a maximum dispatch level; and (v) unless such information has previously been made available to the Office of the Interconnection, sufficient information, as specified in the PJM Manuals, to enable the Office of the Interconnection to model the flow into the PJM Region of any energy from the External Resources scheduled in accordance with the Offer Data.

(c) Offers for External Resources on a resource-specific basis shall specify the resource being offered, along with the information specified in the Offer Data as applicable.

1.10.6 External Market Buyers.

(a) Deliveries to an External Market Buyer not subject to Dynamic Transfer by the Office of the Interconnection shall be delivered on a block loaded basis to the bus or buses at the electrical boundaries of the PJM Region, or in such area with respect to an External Market Buyer's load within such area not served by Network Service, at which the energy is delivered to or for the External Market Buyer. External Market Buyers shall be charged (which charge may be positive or negative) at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing bus or buses.

(b) An External Market Buyer's hourly schedules for energy purchased from the PJM Interchange Energy Market shall conform to the ramping and other applicable requirements of the interconnection agreement between the PJM Region and the Control Area to which, whether as an intermediate or final point of delivery, the purchased energy will initially be delivered.

(c) The Office of the Interconnection shall curtail deliveries to an External Market Buyer if necessary to maintain appropriate reserve levels for a Control Zone as defined in the PJM Manuals, or to avoid shedding load in such Control Zone.

1.10.7 Bilateral Transactions.

Bilateral transactions as to which the parties have notified the Office of the Interconnection by the deadline specified in section 1.10.1A above that they elect not to be included in the Day-ahead Energy Market and that they are not willing to incur Transmission Congestion Charges in the Real-time Energy Market shall be curtailed by the Office of the Interconnection as necessary to reduce or alleviate transmission congestion. Bilateral transactions that were not included in the Day-ahead Energy Market and that are willing to incur congestion charges and bilateral transactions that were accepted in the Day-ahead Energy Market shall continue to be implemented during periods of congestion, except as may be necessary to respond to Emergencies.

1.10.8 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers and PRD Curves properly submitted by PRD Providers; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv) the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated flowgates to the extent provided by Tariff, Attachment K-Appendix, section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) By 1:30 p.m., or as soon as practicable thereafter, of the day before each Operating Day, or such other deadline as may be specified by the Office of the Interconnection in the PJM Manuals, the Office of the Interconnection shall: (i) post the aggregate Day-ahead Energy Market results; (ii) post the Day-ahead Prices; and (iii) inform the Market Sellers, Market Buyers, and Economic Load Response Participants of their scheduled injections, withdrawals, and demand reductions respectively. The foregoing notwithstanding, the deadlines set forth in this subsection shall not apply if the Office of the Interconnection is unable to obtain Market Participant bid/offer data due to extraordinary circumstances. For purposes of this subsection, extraordinary circumstances shall mean a technical malfunction that limits, prohibits or

otherwise interferes with the ability of the Office of the Interconnection to obtain Market Participant bid/offer data prior to 11:59 p.m. on the day before the affected Operating Day. Extraordinary circumstances do not include a Market Participant's inability to submit bid/offer data to the Office of the Interconnection. If the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day as a result of such extraordinary circumstances, the Office of the Interconnection shall notify Members as soon as practicable.

(c) Following posting of the information specified in section 1.10.8(b), and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, the Office of the Interconnection shall revise its schedule of generation resources to reflect updated projections of load, conditions affecting electric system operations in the PJM Region, the availability of and constraints on limited energy and other resources, transmission constraints, and other relevant factors.

(d) Market Buyers shall pay PJMSettlement and Market Sellers shall be paid by PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is positive. Market Buyers shall be paid by PJMSettlement and Market Sellers shall pay PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Tariff, Attachment K-Appendix, section 3.3A. Notwithstanding the foregoing, if the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day due to extraordinary circumstances as described in subsection (b) above, it will be declared a Market Suspension, and Day-ahead Prices shall be determined pursuant to Operating Agreement, Schedule 1, section 2.6.1. If the Office of the Interconnection declares a Market Suspension, it shall notify Market Participants of the Market Suspension as soon as practicable.

(e) If the Office of the Interconnection discovers a *potential* error in prices and/or cleared quantities in the Day-ahead Energy Market or Day-ahead Ancillary Services Markets, or the Real-time Energy Market or Real-time Ancillary Services Markets after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants as soon as possible after it is found, but in no event later than 12:00 p.m. of the second Business Day following the Operating Day for the Real-time Energy Market and Real-time Ancillary Services Markets, and no later than 5:00 p.m. of the second Business Day following the initial publication of the results for the Day-ahead Energy Market and Day-ahead Ancillary Services Markets. After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, *along with a description detailing the cause and scope of the error*, by no later than 5:00 p.m. of the fifth Business Day following the Operating Day for the Real-time Energy Market and Real-time Ancillary Services Markets, and no later than 5:00 p.m. of the fifth Business Day following the initial publication of the results in the Day-ahead Energy Market and Day-ahead Ancillary Services Markets. *The provided description will not contain information that is market sensitive or confidential.* Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating

Day for the Day-ahead Energy Market, Real-time Energy Market, and Day-ahead Ancillary Services Markets, and Real-time Ancillary Service Markets. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced market results are under publicly noticed review by the FERC.

(f) Consistent with Operating Agreement, section 18.17.1, and notwithstanding anything to the contrary in the Operating Agreement or in the PJM Tariff, to allow the tracking of Market Participants' non-aggregated bids and offers over time as required by FERC Order No. 719, the Office of the Interconnection shall post on its Web site the non-aggregated bid data and Offer Data submitted by Market Participants (for participation in the PJM Interchange Energy Market) approximately four months after the bid or offer was submitted to the Office of the Interconnection.

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, a generation rebidding period shall exist. Typically the rebidding period shall be from the time the Office of the Interconnection posts the results of the Day-ahead Energy Market until 2:15 p.m. on the day before each Operating Day. However, should the clearing of the Day-ahead Energy Market be significantly delayed, the Office of the Interconnection may establish a revised rebidding period. During the rebidding period, Market Participants may submit revisions to generation Offer Data for the next Operating Day. Adjustments to the Day-ahead Energy Market shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 6:30 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 65 minutes prior to the hour in which the adjustment is to take effect, as follows and as specified in section 1.10.9A below:

i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;

ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or

iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or

iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any Start-Up Costs.

(c) An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase in the Day-ahead Energy Market by notifying the Office of the Interconnection of the adjustment in deliveries not later than 65 minutes prior to the hour in which the adjustment is to take effect, but any such adjustment shall not affect the obligation of the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(d) The Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules resulting from the rebidding period by 6:30 p.m. on the day before each Operating Day. The Office of the Interconnection may also commit additional resources after such time as system conditions require. For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this section 1.10, the Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules for the hour.

1.10.9A Updating Offers in Real-time

(a) Each Market Seller may submit Real-time Offers for a resource up to 65 minutes before the applicable clock hour, and such Real-time Offers shall supersede any previous offer for that resource for the clock hour, as further described in the PJM Manuals and subject to the following conditions:

(i) A market-based Real-time Offer shall not exceed the applicable energy offer caps specified in this Schedule. Once a Market Seller's resource is committed for an applicable clock hour, the Market Seller may not increase its Incremental Energy Offer and may only submit a market-based Real-time Offer that is higher than its market-based offer that was in effect at the time of commitment to reflect increases in the resource's cost-based Start-up Costs and cost-based No-load Costs. The Market Seller may elect not to have its market-based offer considered for dispatch and to have only its lowest cost-based offer considered for the remainder of the Operating Day.

(ii) Cost-based Real-time Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2 and the PJM Manuals, as applicable. If a Market Seller submits a market-based Real-time Offer for a particular clock hour in accordance with subsection (c) below, or if updates to a cost-based offer are required by the Market

Seller's approved Fuel Cost Policy, the Market Seller shall update its previously submitted cost-based Real-time Offer.

(iii) If a Market Seller's available cost-based offer is not compliant with Operating Agreement, Schedule 2 and the PJM Manuals at the time a Market Seller submits a market-based Real-time Offer for an applicable clock hour during the Operating Day, the Market Seller must submit an updated cost-based Real-time Offer consisting of an Incremental Energy Offer, Start-up Cost and No-load Cost for that clock hour that is compliant with Operating Agreement, Schedule 2 and the PJM Manuals.

(b) Each Market Seller may submit Real-time Offers for a resource during and through the end of the applicable clock hour to update only the following offer parameters, as further described in the PJM Manuals: (1) Economic Minimum; (2) Economic Maximum; (3) emergency minimum MW; (4) emergency maximum MW; (5) unit availability status; (6) fixed output indicator; (7) Synchronized Reserve maximum MW; and (8) Secondary Reserve maximum MW. Such Real-time Offers shall supersede any previous offer for that resource for the clock hour.

1.10.9B Offer Parameter Flexibility

(a) Market Sellers may, in accordance with sections 1.10.1A and 1.10.9A above, this section 1.10.9B, and the PJM Manuals, update offer parameters at any time up to 65 minutes before the applicable clock hour, including prior to the close of the Day-ahead Energy Market and prior to the close of the rebidding period specified in section 1.10.9, except that Market Sellers may not update their offers for the supply of energy, Secondary Reserve, Synchronized Reserve, Non-Synchronized Reserve, or demand reduction: (1) during the period after the close the Day-ahead Energy Market and prior to the posting of the Day-ahead Energy Market results pursuant to section 1.10.8(b); or (2) during the period after close of the rebidding period and prior to PJM announcing the results of the rebidding period pursuant to section 1.10.9(d).

(b) For generation resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) cost-based Start-up Costs; (2) cost-based No-load Costs; (3) Incremental Energy Offer; (4) Economic Minimum and Economic Maximum; (5) emergency minimum MW and emergency maximum MW; (6) ramp rate; (7) Synchronized Reserve maximum MW; (8) Secondary Reserve maximum MW; and (9) for Real-time Offers only, (i) notification time and (ii) for uncommitted hours only, Minimum Run Time. Notwithstanding the foregoing, Market Sellers of generation resources may vary the notification time for each clock hour for purposes of committing Non-Synchronized Reserve and offline Secondary Reserve in both the Day-ahead and Real-time reserve commitments.

(c) For Economic Load Response Participant resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) shutdown costs, (2) Incremental Energy Offer; (3) Economic Minimum; (4) Economic Maximum; and (5) for Real-time Offers only, (i) notification time and (ii) for uncommitted hours only, minimum down time.

(d) After the announcement of the results of the rebidding period pursuant to section 1.10.9(d), a Market Seller may submit a Real-time Offer where offer parameters may differ from the offer originally submitted in the Day-ahead Energy Market, except that a Market Seller may

not submit a Real-time Offer that changes, of the offer parameters listed in section 1.10.1A(d), the MW amounts specified in the Incremental Energy Offer, MW amounts specified in the ramp rate, maximum run time, and availability; provided, however, Market Sellers of dual-fueled resources may submit Real-time Offers for such resources that change the availability of a submitted cost-based offer.

1.12 Dynamic Transfers.

(a) An entity that owns or controls a generating resource in the PJM Region may request that the Transmission Provider electrically remove all or part of the generating resource's output from the PJM Region through a Dynamic Transfer of the output to load outside the PJM Region. Such output shall not be available for economic dispatch by the Office of the Interconnection. A Market Participant otherwise eligible pursuant to section 3.2.3 to submit start-up and no-load values of a generating unit for consideration in calculation of the Energy Make Whole credit shall not be so eligible if all of the output of the generating unit is transferred outside of the PJM Region by a Dynamic Transfer.

(b) An entity that owns or controls a generating resource outside of the PJM Region may request that the Transmission Provider electrically add all or part of the generating resource's output to the PJM Region through a Dynamic Transfer of the output to load inside the PJM Region. A Market Participant otherwise eligible pursuant to section 3.2.3 to submit start-up and no-load values of a generating unit for consideration in calculation of the Energy Make Whole credit shall be so eligible only if all of the output of the generating unit is transferred into the PJM Region by a Dynamic Transfer.

(c) The Transmission Provider may implement Dynamic Transfers pursuant to a request under subsections (a) or (b) above, provided that the requesting entity can demonstrate to the satisfaction of the Transmission Provider that the requesting entity has arranged for the provision of signal processing and communications from the generating unit to the Office of the Interconnection and other participating control areas and remains in compliance with any other procedures and operational requirements established by the Office of the Interconnection regarding Dynamic Transfer as set forth in the PJM Manuals.

(d) An entity requesting a Dynamic Transfer shall be responsible for reserving the amount of transmission service necessary to deliver the range of the Dynamic Transfer and any required ancillary services as applicable. Firm or non-firm transmission service may be used to deliver Dynamic Schedules. Dynamic Schedules are not eligible to provide ancillary services. Only firm transmission service may be used to deliver Pseudo-Ties. Pseudo-Ties are eligible to provide Regulation, Synchronized Reserve and Non-Synchronized Reserve as further described in the PJM Manuals. An entity seeking to utilize a Dynamic Schedule to coordinate operations and beneficially manage congestion in real time with PJM may execute a mutually agreeable interregional congestion management agreement as contemplated in Section 2.6A of this Schedule. An entity seeking to utilize a Pseudo-Tie shall execute a mutually agreeable interregional congestion management agreement as contemplated in Section 2.6A of this Schedule. An entity seeking to utilize a Dynamic Transfer shall execute an agreement prescribing the requirements that must be met before PJM will implement the requested Dynamic Transfer. Dynamic Schedule transactions that occur in real time pursuant to such a congestion management agreement may utilize after-the-fact transmission reservations to account for actual energy transfers.

(e) The Market Participant shall cooperate with PJM to ensure that changes in the Dynamic Transfer value do not adversely impact PJM's management of the PJM Area Control Error in a manner unacceptable to PJM, and, in the event that PJM, in its sole discretion, determines

that the Market Participant's actions in this regard are unacceptable, PJM may terminate the Dynamic Transfer arrangement and may require such additional conditions as it deems appropriate prior to any further Dynamic Transfers.

(f) Market Sellers of generators and other sources otherwise eligible pursuant to Schedule 2 of the PJM Tariff to receive compensation for providing reactive supply and voltage control shall not be so eligible if the generating unit is outside of the PJM Region regardless of whether the generating unit is transferred into the PJM Region by a Dynamic Transfer.

3.2 Market Settlements.

If a dollar-per-MW-hour value is applied in a calculation under this section 3.2 where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW hour value is divided by the number of Real-time Settlement Intervals in the hour.

3.2.1 Spot Market Energy.

(a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with Tariff, Attachment K-Appendix, section 2.

(b) Each Market Participant shall be charged for all of its Market Participant Energy Withdrawals scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price to be served in the PJM Interchange Energy Market.

(c) Each Market Participant shall be paid for all of its Market Participant Energy Injections scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price to be delivered to the PJM Interchange Energy Market.

(d) For each Day-ahead Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its Market Participant Energy Withdrawals scheduled times the Day-ahead System Energy Price and the sum of its Market Participant Energy Injections scheduled times the Day-ahead System Energy Price.

(e) For each Real-time Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its real-time Market Participant Energy Withdrawals less its scheduled Market Participant Energy Withdrawals times the Real-time System Energy Price and the sum of its real-time Market Participant Energy Injections less scheduled Market Participant Energy Injections times the Real-time System Energy Price. The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Tariff, Attachment K-Appendix, section 3.1A shall be used in determining the real-time Market Participant Energy Withdrawals and Market Participant Energy Injections used to calculate Spot Market Energy charges under this subsection (e).

(f) For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the megawatts of real-time energy injections to be delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region

3.2.2 Regulation.

(a) Each Market Participant that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation Requirement of such Regulation Zone for the hour, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). A Market Participant with an hourly Regulation Obligation shall be charged the pro rata share of the sum of the Regulation market mileage clearing price credits and Regulation market capability clearing price credits for the Real-time Settlement Intervals in an hour.

Regulation Charge = Hourly Regulation Obligation Share * (sum of the Real-time Settlement Interval Regulation credits in an hour)

(b) Each Market Participant supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection shall be credited for each of its resources such that the calculated credit for each increment of Regulation provided by each resource shall be the higher of: (i) the Regulation market-clearing price; or (ii) the sum of the applicable Regulation offers for a resource determined pursuant to section 3.2.2A.1 of this Schedule, the resource-specific shoulder opportunity costs described in subsection (e) below, the resource-specific inter-temporal opportunity costs discussed in subsection (d), and the resource-specific opportunity costs discussed in subsection (e) of this section.

(c) The Office of the Interconnection shall commit resources to provide Regulation every 30 minutes, for the clock intervals of the first 30 minutes of an hour and the second 30 minutes of an hour, up to the Regulation Requirement of such Regulation Zone. The Office of the Interconnection shall select resources in merit order, taking into account the resource's mileage Regulation offer, capability Regulation offer, and estimated resource-specific opportunity cost, all converted into their performance adjusted values as further detailed in the PJM Manuals. The total Regulation market-clearing price in each Regulation Zone shall be determined in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval. The total Regulation market-clearing price shall include: (i) the mileage Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 below shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in Tariff, Attachment K-Appendix, section 1.10.1A(e).

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the resource-specific opportunity costs (in dollars) of a resource offering to sell Regulation in each regulating interval, except for hydroelectric resources, shall be equal to the area bounded by (i) Locational Marginal Price at the generation bus for the regulating resource, (ii) the resource's Final Offer, (iii) the resource's tracking ramp-rate limited expected output level if it had been

dispatched for energy in economic merit order, as further described in the PJM Manuals, and (iv) the resource's regulation set point on the energy schedule curve on which the resource is running in the PJM Interchange Energy Market. The area is divided by the resource performance score and further divided by the resource's regulation assigned megawatt to convert to dollars per megawatt.

For hydroelectric resources offering to sell Regulation in a regulating interval, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the full value of the Locational Marginal Price at that generation bus for each megawatt of Regulation capability.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the expected Locational Marginal Price at the generation bus for the hydroelectric resource and the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. Estimated opportunity costs shall be zero for hydroelectric resources for which the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those Real-time Settlement Intervals during which all available units at the hydroelectric resource were operating is higher than the actual Locational Marginal Price at the generator bus for the Real-time Settlement Interval.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating and the expected Locational Marginal Price at the generation bus for the hydroelectric resource. Estimated opportunity costs shall be zero for hydroelectric resources for which the actual Locational Marginal Price at the generator bus for the Real-time Settlement Interval is higher than the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those Real-time Settlement Intervals during which all available units at the hydroelectric resource were operating.

For the purpose of committing resources and setting Regulation market clearing prices, the Office of the Interconnection shall utilize day-ahead Locational Marginal Prices to calculate the average of the Locational Marginal Price values used in the calculation for opportunity costs for hydroelectric resources. For the purposes of settlements, the Office of the Interconnection shall

utilize the real-time Locational Marginal Prices to calculate the average of the Locational Marginal Price used in the calculation for opportunity costs for hydroelectric resources.

Opportunity costs for Economic Load Response Participant resources and regulation-only resources to provide Regulation are zero for the purpose of committing resources, setting Regulation clearing prices, and settlements.

(e) In determining the credit under subsection (b) to a Market Participant selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for (1) each Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Regulation, and (2) the two Real-time Settlement Intervals preceding the regulation commitment and the two Real-time Settlement Intervals following the regulation commitment in accordance with the PJM Manuals and below.

The unit-specific opportunity cost in dollars, incurred during the Real-time Settlement Interval, in which the Regulation obligation is fulfilled, shall be equal to the area bounded by (i) the Locational Marginal Price at the generation bus for the regulating resource, (ii) the resource's Final Offer, (iii) the generation resource's tracking ramp-rate limited expected output level if it had been dispatched in economic merit order, as further described in the PJM Manuals, and (iv) the generation resource's regulation set point, and adjusted for the performance score of the resource. Opportunity costs for Economic Load Response Participant or regulation only resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during each of the preceding two Real-time Settlement Intervals of the regulation commitment shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating Real-time Settlement Interval in order to provide Regulation and the resource's tracking expected ramp rate limited output in each of the preceding two Real-time Settlement Intervals of the regulation commitment times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in each of the preceding two Real-time Settlement Intervals of the regulation commitment and the energy offer, using the Final Offer, at the megawatt level of the Regulation set point for the resource in the initial regulating Real-time Settlement Interval, in the PJM Interchange Energy Market, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during each of the following two Real-time Settlement Intervals of the regulation commitment shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating Real-time Settlement Interval in order to provide Regulation and the resource's tracking expected ramp-rate limited output in each of the following two Real-time Settlement Intervals of the regulation commitment times, and (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in each of the following two Real-time Settlement Intervals of the regulation

commitment and the energy offer, using the Final Offer, at the megawatt level of the Regulation set point for the resource in final regulating hour, in the PJM Interchange Energy Market all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Market Participant in a Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

(g) To determine the Regulation market mileage-clearing price, the Office of the Interconnection shall adjust the submitted mileage offer for each resource in accordance with the historical performance score of that resource, and the amount of historically dispatched Regulation (mileage) calculated by the Office of the Interconnection. The maximum adjusted mileage offer of all cleared resources will set the Regulation market mileage-clearing price.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions, will be credited for Regulation mileage by multiplying the assigned MW(s) by the Regulation market mileage-clearing price, by the ratio between the requested mileage for the Regulation dispatch signal and the historic requested mileage for the Regulation dispatch signal, calculated by the Office of the Interconnection, and by the Regulation resource's performance score calculated in accordance with subsection (j) of this section. For purposes of calculating the credit for Regulation performance, if the hourly movement of the Regulation A dispatch signal equals zero, a value of 0.1 will be used in its place.

(h) The Office of the Interconnection shall divide each Regulation resource's capability offer by the historic performance score for the resource for the purposes of committing resources and setting the market clearing prices.

The Office of the Interconnection shall calculate the Regulation market capability-clearing price for each Regulation Zone by subtracting the Regulation market mileage-clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the Regulation market capability-clearing price for that market Real-time Settlement Interval.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions will be credited for Regulation capability based on the assigned MW and the capability Regulation market-clearing price multiplied by the Regulation resource's performance score calculated in accordance with subsection (j) of this section.

(i) In accordance with the processes described in the PJM Manuals, the Office of the Interconnection shall: (i) calculate inter-temporal opportunity costs for each applicable resource; (ii) include such inter-temporal opportunity costs in each applicable resource's offer to sell frequency Regulation service; and (iii) account for such inter-temporal opportunity costs in the Regulation market-clearing price.

(j) The Office of the Interconnection shall calculate each Regulation resource's performance score. The performance score shall be a function of the difference in the energy provided versus the energy requested by the Regulation signal while scaling for the number of samples. The error measured shall be the difference of the resources response and the dispatch signal, adjusted by the assigned MW and signal dispatch of the Regulation resource. The performance score is calculated using the following equations:

Performance Score = 1 - 1/n ∑ Abs (Error);

Error = Average of Abs (Abs (Response - Regulation Signal) / (0.5*Interval Average Regulation Signal + 0.5*AREG)); and

n = the number of samples in the interval
AREG = assigned regulation megawatt.

The Office of the Interconnection shall calculate a performance score for each Regulation resource for each five-minute period the Regulation resource is assigned to provide Regulation.

The historic performance score will be based on a 100 clock-hour rolling average of the Real-time Settlement Interval performance scores, with consideration of the qualification score, for resources without adequate historical data, as defined in the PJM Manuals.

Regulation resources that have a Real-time Settlement Interval performance score below 25% will be ineligible for Regulation credits for that Real-time Settlement Interval.

Regulation resources that have historical performance scores fall below 40% shall be disqualified from providing Regulation until they are able to re-qualify, as defined in the PJM Manuals.

(k) During a Market Suspension where the suspension is less than or equal to 24 consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Regulation, the resources providing Regulation at the direction of the Office of the Interconnection will be compensated based on a calculated Regulation market-clearing price. Regulation market-clearing prices for each Real-time Settlement Interval associated with such Market Suspension shall be the average of the Regulation market-clearing prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

During a Market Suspension where the suspension is greater than 24 consecutive hours, if the Office of the Interconnection is assigning Regulation, resources providing Regulation at the direction of the Office of the Interconnection will be compensated based on a calculated Regulation clearing price. The Regulation clearing price for each Real-time Settlement Interval will be determined by calculating a Regulation clearing cost for the online resources providing Regulation during the Market Suspension. The resource's Regulation clearing cost is determined by the summation of their adjusted Regulation offer and adjusted opportunity cost. The

opportunity cost will be based on the resource's cost-based offer and will be determined as follows:

> For online resources providing Regulation on a cost-based offer at the time of the Market Suspension, that cost-based offer will be used.
>
> For online resources providing Regulation on a price-based offer at the time of the Market Suspension, the Office of the Interconnection shall use the cheapest available cost-based offer based on the dispatch cost formula as defined in Operating Agreement, Schedule 1, section 6.4.1(g) using the available cost-based offers in the Office of the Interconnection system at the time of the Market Suspension.

The highest cost resource, based on this Regulation clearing cost, will set the Regulation market-clearing price for each hour of the Market Suspension.

During a Market Suspension, if the Office of the Interconnection is not assigning Regulation resources, then the Regulation market-clearing price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period and no resource-specific opportunity cost will be calculated.

During a Market Suspension, the following Regulation components for all Real-time Settlement Intervals in the Market Suspension period will be determined as follows:

(i) If the regulation performance score cannot be calculated during a Market Suspension, the historic performance score will be used for the Market Suspension period.

(ii) If the regulation mileage cannot be calculated during a Market Suspension, the mileage will be set to one (1) for the Market Suspension period.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) For each Regulation market clearing interval, the Office of the Interconnection shall conduct a Regulation three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the Regulation three-pivotal supplier test shall be capped in the interval in which they failed the test at their cost based offers as determined pursuant to Tariff, Attachment K-Appendix, section 1.10.1A(e). A Regulation supplier fails the three-pivotal supplier test in any Regulation market clearing interval in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

(b) For the purposes of conducting the three-pivotal supplier test pursuant to this section, the following applies:

(i) The Regulation three-pivotal supplier test will include in the definition of available supply all offer megawatts from resources capable of satisfying the Regulation Requirement of the PJM Region multiplied by the historic performance score of the resource for which the capability cost-based offer plus the mileage cost-based offer plus any eligible opportunity costs is no greater than 150% of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The Regulation three-pivotal supplier test will apply on a Regulation supplier basis (i.e. not a resource by resource basis) and only the Regulation suppliers that fail the three-pivotal supplier test will have their Regulation offers capped. A Regulation supplier for the purposes of this section includes corporate affiliates. Regulation from resources controlled by a Regulation supplier or its affiliates, whether by contract with unaffiliated third parties or otherwise, will be included as Regulation of that Regulation supplier. Regulation provided by resources owned by a Regulation supplier but controlled by an unaffiliated third party, whether by contract or otherwise, will be included as Regulation of that third party.

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the Regulation Requirement for the Regulation clearing interval to determine the residual supply index. Where the residual supply index for Regulation three pivotal suppliers is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Energy Uplift.

(a) A Market Seller's pool-scheduled resources shall be credited as specified below for Energy Make Whole credits.

(b) Day-ahead Energy Make Whole credits shall be calculated in the following manner for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for Start-up Costs and No-load Costs and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. PJM shall also (i) determine whether any resources were scheduled in the Day-ahead Energy Market to provide Black Start Service, Reactive Services or transfer interface control during the Operating Day because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day in order to minimize the total cost of Operating Reserves associated with the provision of such

services and reflect the most accurate possible expectation of real-time operating conditions in the day-ahead model, which resources would not have otherwise been committed in the day-ahead security-constrained dispatch and (ii) report on the day following the Operating Day the megawatt quantities scheduled in the Day-ahead Energy Market for the above-enumerated purposes for the entire RTO.

Except as provided in section 3.2.3(n) below, if the total offered price for Start-up Costs (shutdown costs for Economic Load Response Participant resources) and No-load Costs and energy summed over all Day-ahead Settlement Intervals exceeds the total value summed over all Day-ahead Settlement Intervals, the difference shall be credited to the Market Seller as day-ahead Energy Make Whole credits.

However, for the Day-ahead Settlement Intervals in which the resource is scheduled to provide energy in the Operating Day and the resource actually provides energy in at least one Real-time Settlement Interval in an hour that corresponds to such scheduled Day-ahead Settlement Intervals, a resource's day-ahead Energy Make Whole credit shall be reduced by the greater of zero or the difference of the resource's day-ahead Energy Make Whole target and the balancing Energy Make Whole target, as determined below.

A resource's day-ahead Energy Make Whole target shall be determined in accordance with the following equation:

(A + B) - C

Where:

A = Start-up Costs

B = the sum of day-ahead No-load Costs and energy over the applicable Real-time Settlement Intervals that correspond with Day-ahead Settlement Intervals in which the resource is scheduled. The day-ahead No-load Costs and energy are divided by twelve to determine the cost for each Real-time Settlement Interval.

C = the sum of the day-ahead revenues calculated for each Real-time Settlement Interval that corresponds with a Day-ahead Settlement Interval in which the resource is scheduled, where the day-ahead revenue for each such Real-time Settlement Interval equals the product of the megawatt amount of energy scheduled in the Day-ahead Energy Market and the Day-ahead Price at the applicable pricing point for the resource divided by twelve.

A resource's balancing Energy Make Whole target shall be determined in accordance with the following equation:

D – (E + F)

Where:

D = the Real-time Cost, as defined in subsection 3.2.3(e-2)(ii) of this section, summed over all Real-time Settlement Intervals that correspond to the Day-ahead Settlement Intervals in which the resource was scheduled;

E = [(the megawatt amount of energy provided in the Real-time Energy Market minus the megawatt amount of energy scheduled in the Day-ahead Energy Market) multiplied by the Real-time Price at the applicable pricing point for the resource] plus the sum of the day-ahead revenues as determined in part C of the above formula for determining the Day-ahead Energy Make Whole target, summed over the Real-time Settlement Intervals that correspond to the Day-ahead Settlement Intervals in which the resource was scheduled; and

F = the sum of all Other Market Revenues as defined in subsection 3.2.3(e-2)(ii) of this section, over the Real-time Settlement Intervals that correspond to the Day-ahead Settlement Intervals in which the resource was scheduled.

(c) The sum of the foregoing credits calculated in accordance with section 3.2.3(b) plus any unallocated charges from section 3.2.3(h) and Tariff, Attachment K-Appendix, 5.1.7, and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of Energy Make Whole credits in the Day-ahead Energy Market.

(d) The cost of Energy Make Whole credits in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load ((a) net of Behind The Meter Generation expected to be operating, but not to be less than zero; and (b) excluding Direct Charging Energy), accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day and accepted Up-to Congestion Transactions in the Day-ahead Energy Market in megawatt-hours for the Operating Day at the sink of the transaction; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside such area pursuant to Tariff, Attachment K-Appendix, section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Energy Make Whole credits in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Tariff, Schedule 6A. The cost of Energy Make Whole credits in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load ((a) net of operating Behind The Meter Generation; and (b) excluding Direct Charging Energy) in such Zone, served under Network Transmission Service,

in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

(e) (i) Pool-scheduled generation resources that operate for at least one Real-time Settlement Interval within the pool-scheduled commitment period are eligible for balancing Energy Make Whole credits as further detailed in this section and in the PJM Manuals. Balancing Energy Make Whole credits eligibility for Economic Load Response Participant resources is detailed in Tariff, Attachment K-Appendix, section 3.2.3(o-1) of this section. A pool-scheduled generation resource's eligibility for balancing Energy Make Whole credits begins at the first Real-time Settlement Interval of a pool-scheduled commitment. The generation resource remains eligible for balancing Energy Make Whole credits until the later of:

1) the Real-time Settlement Interval corresponding to the end of its Day-ahead Energy Market commitment or the end of its Minimum Run Time, as applicable

or

2) the Real-time Settlement Interval when the resource is no longer running under the direction of the Office of the Interconnection.

Additionally, generation resource types with no soak process in the Start-up Cost are eligible for balancing Energy Make Whole credits for a pre-commitment period prior to the first Real-time Settlement Interval of the pool-scheduled commitment to account for ramping costs. The pre-commitment period begins with the Real-time Settlement Interval when a generation resource comes online but may not begin earlier than four Real-time Settlement Intervals (20 minutes) prior to the first Real-time Settlement Interval of the pool-scheduled commitment. However, a generation resource is only eligible for this pre-commitment period if the price and megawatt quantities submitted as part of its Incremental Energy Offer, using the lesser of the Final Offer or Committed Offer as determined using the Actual MWh during the pre-commitment period, are less than or equal to the price and megawatt quantities of its Incremental Energy Offer using the Committed Offer for the first hour of the commitment. Generation resource types with a soak process in the Start-up Cost are not eligible during the pre-commitment period.

Pool-scheduled generation resources that are released by the Office of Interconnection and ramping offline are additionally eligible for balancing Energy Make Whole credits for post-commitment Real-time Settlement Intervals until the Real-time Settlement Interval that the generation resource goes offline; however, eligibility shall not extend beyond the Real-time Settlement Interval in which the resource is no longer running under the direction of the Office of Interconnection plus the number of Real-time Settlement Intervals corresponding to the allowable ramp down period for the resource type, as specified in the PJM Manuals. However, a generation resource is only eligible for this post-commitment period if the price and megawatt quantities submitted as part of its Incremental Energy Offer, using the lesser of the Final Offer or Committed Offer as

determined using the Actual MWh during the post-commitment period, is less than or equal to the price and megawatt quantities of its Incremental Energy Offer using the Committed Offer for the last hour of the commitment.

(ii) The balancing Energy Make Whole credit calculation will be conducted on a segmented basis. For each Operating Day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two Segments for each resource.

The first Segment will be defined as the greater of the applicable day-ahead commitment and Minimum Run Time specified at the time of commitment (minimum down time specified at the time of commitment for Economic Load Response Participant resources).

Further, if a generation resource is no longer running under the direction of the Office of the Interconnection within 30 minutes after the end of the first Segment, the first Segment will also include the remainder of the Real-time Settlement Intervals in which the resource operated at the direction of the Office of the Interconnection

The second Segment will be defined as any block of contiguous Real-time Settlement Intervals the resource runs under the direction of the Office of the Interconnection in excess of the first Segment.

Notwithstanding the foregoing, each Segment shall be limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

(iii) If a Market Seller submits an offer parameter that exceeds the applicable approved parameter limit on a parameter-limited schedule for a generation resource and such parameter affects the MW dispatch level of the resource in a given settlement interval, the resource will remain eligible for the energy uplift credit calculation but shall not recover any costs incurred during the affected settlement intervals. If such parameter impacts the commitment decision in a manner that could lead to the Office of the Interconnection committing the generation resource to produce energy for longer than it otherwise would have, the resource will not be eligible for the energy uplift credit calculation for the commitment duration. A generation resource that is the subject to an offer parameter on a parameter-limited schedule that exceeds its approved parameter limits may still be eligible for energy uplift credits if the Market Seller of such resource can justify to the Office of the Interconnection that the need to operate outside of such unit-specific parameters was the result of an actual constraint.

A Market Seller shall provide to the Market Monitoring Unit and the Office of the Interconnection its request to receive energy uplift credits for such operation, along with documentation explaining in detail the reasons for operating its resource outside of its

unit-specific parameters, within thirty calendar days following the issuance of the billing statement for the Operating Day. The Market Seller shall also respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection. The Market Monitoring Unit shall evaluate such request for compensation and provide its determination of whether there was an exercise of market power to the Office of the Interconnection by no later than twenty-five calendar days after receiving the Market Seller's request for compensation. The Office of the Interconnection shall make its determination whether the Market Seller justified that it is entitled to receive energy uplift credits for such operation of its resource for the day(s) in question, by no later than thirty calendar days after receiving the Market Seller's request for compensation.

(iv) Nuclear generation resources shall not be eligible for energy uplift payments unless: 1) the Office of the Interconnection directs such resources to reduce output, in which case, such units shall be compensated in accordance with Tariff, Attachment K-Appendix, section 3.2.3(f) and the parallel provision of Operating Agreement, Schedule 1, section 3.2.3(f); or 2) the resource submits a request for a risk premium to the Market Monitoring Unit under the procedures specified in Tariff, Attachment M – Appendix, section II.B. A nuclear generation resource (i) must submit a risk premium consistent with its agreement under such process, or, (ii) if it has not agreed with the Market Monitoring Unit on an appropriate risk premium, may submit its own determination of an appropriate risk premium to the Office of the Interconnection, subject to acceptance by the Office of the Interconnection, with or without prior approval from the Commission.

(e-1) The Tracking Ramp Limited Desired (TRLD) metric is used in the calculation of balancing Energy Make Whole credits and generator deviation charges as a representation of the level at which the resource would be desired if operating as requested by the Office of the Interconnection. There are two Tracking Ramp Limited Desired metrics, one measured in MW (power) and the other measured in MWh (energy), each of which are calculated as described below and as further detailed in the PJM Manuals. The Tracking Ramp Limited Desired MWh (energy) calculated for each Real-time Settlement Interval shall be used in the calculation of balancing Energy Make Whole credits and generator deviations. The Tracking Ramp Limited Desired MWh (energy) value represents the expected energy produced between the start of the Real-time Settlement Interval and the end of the Real-time Settlement Interval.

For purposes of this Tariff, Attachment K-Appendix, section 3.2.3, the minimum operating limit used herein shall be the Economic Minimum unless the Office of the Interconnection has declared Minimum Generation Emergency conditions, in which case it shall be the emergency minimum. Also, the maximum operating limit shall be the Economic Maximum unless the Office of the Interconnection has declared Maximum Emergency conditions, in which case it shall be the emergency maximum.

(i) Tracking Ramp Limited Desired MW (power) is an adjusted metric that accounts for the impact of Regulation and reserve assignments or manual dispatch instructions.

The Tracking Ramp Limited Desired MW (power) calculation starts at time t_0, which is when a generation resource is first expected by the Office of Interconnection to be online or when a generation resource is dispatchable, while honoring soak time differences, as further detailed in the PJM Manuals.

The Tracking Ramp Limited Desired MW (power) metric will be calculated as follows. For the Real-time Settlement Interval equal to t_0,

If a generation resource does not have a soak process and is directed to come online as soon as possible,

TRLD MW (power) = 0

Otherwise,
TRLD MW (power)
= Max [Min (LMP Desired MW, Dispatch MW), Tracking Desired Economic Minimum]

Where:
LMP Desired MW = the generation resource's expected output level based on its Final Offer at the Real-time Locational Marginal Price from the dispatch run at the applicable pricing point
Dispatch MW = energy dispatch signal MW from the dispatch run
Tracking Desired Economic Minimum = the generation resource's minimum operating limit, as specified in Tariff, Attachment K-Appendix, section 3.2.3(e-1), unless any of the following conditions occur,

- If a resource is requested to increase output due to a transmission constraint or other reliability issue, Tracking Desired Economic Minimum = the lower limit from the manual dispatch instruction as directed by the Office of the Interconnection.

- If the resource's minimum operating limit increases by more than 5% of the resource's minimum operating limit at the time of commitment, the minimum operating limit at the time of commitment will be used.

For each Real-time Settlement Interval after the resource's initial start time, t_0, Tracking Ramp Limited Desired MW (power) shall be calculated as follows:

$$\text{TRLD MW}_t \text{ (power)} = \text{TRLD MW}_{t-1} \pm \text{Ramp}_t$$

Where:
t = Start time of Real-time Settlement Interval for which the metric is being calculated
Ramp = Increase or decrease in MW calculated using the Real-time Locational Marginal Price from the dispatch run at the applicable pricing point, the resource's

Final Offer, and the ramp rate parameters. The increase or decrease in MW is restricted by the most limiting of the following parameters among the ramp rate, the Tracking Desired Economic Minimum, and the Tracking Desired Economic Maximum, where:

Tracking Desired Economic Minimum = defined above in the calculation for TRLD MW_{t0}
Tracking Desired Economic Maximum = the generation resource's maximum operating limit unless any one of the following conditions occur:

- If a resource is requested to decrease output due to a transmission constraint or other reliability issue, Tracking Desired Economic Maximum = the upper limit from the manual dispatch instruction as directed by the Office of the Interconnection.

- If a resource's maximum operating limit decreases by more than 5% of the resource's maximum operating limit at the time of commitment, the maximum operating limit at the time of commitment will be used.

The Tracking Ramp Limited Desired MW (power) value will be further adjusted, as specified below, if the resource has a regulation or reserve assignment and is unable to provide such assignment while generating the initial Tracking Ramp Limited Desired MW due to the resource's applicable operating parameters.

- If the Tracking Ramp Limited Desired MW is above the highest MW point at which the resource can provide the Regulation or reserve assignments, the Tracking Ramp Limited Desired MW will be lowered to the highest point at which it can provide the assignment(s) based on the resource's applicable operating parameters.

- If the Tracking Ramp Limited Desired MW is below the lowest MW point at which the resource can provide the Regulation assignment, the Tracking Ramp Limited Desired MW will be increased to the lowest point at which it can provide the regulation assignment based on the resource's applicable operating parameters.

This adjusted Tracking Ramp Limited Desired MW value is used in calculating the Tracking Ramp Limited Desired MW (power) for subsequent intervals.

(ii) An unadjusted Tracking Ramp Limited Desired MW (power) that excludes the impact of Regulation and reserve assignments or manual dispatch instructions is also calculated for conversion to an unadjusted Tracking Ramp Limited Desired MWh (energy) metric which is used in the Other Market Revenue and Opportunity Cost Owed calculations described in subsection 3.2.3(e-2)(i). The unadjusted Tracking Ramp Limited Desired MW (power) metric will be calculated as follows.

For the Real-time Settlement Interval equal to $t_{0,}$ the unadjusted Tracking Ramp Limited Desired MW (power) equals the Tracking Ramp Limited Desired MW $(power)_{t0}$ as calculated in subsection (i) directly above excluding the impact of regulation and reserve assignments or manual dispatch instructions.

For each Real-time Settlement Interval after the start time, t_0, the unadjusted Tracking Ramp Limited Desired MW (power) shall be calculated as follows:

$$\text{unadjusted TRLD } MW_t \text{ (power)} = \text{unadjusted TRLD } MW_{t-1} \pm Ramp_t$$

Where:

t = Start time of Real-time Settlement Interval for which the metric is being calculated

Ramp = Increase or decrease in MW calculated using the Real-time Locational Marginal Price from the dispatch run at the applicable pricing point, the resource's Final Offer, and the ramp rate parameters. The increase or decrease in MW is restricted by the most limiting parameter among the ramp rate, the unadjusted economic minimum, and the unadjusted economic maximum, where:

unadjusted economic minimum = minimum operating limit for the Real-time Settlement Interval unless such minimum operating limit increased by more than 5% of the resource's minimum operating limit at the time of commitment, in which case the minimum operating limit at the time of commitment shall be used.

unadjusted economic maximum = maximum operating limit for the Real-time Settlement Interval unless such maximum operating limit decreased by more than 5% of the resource's maximum operating limit at the time of commitment, in which case the maximum operating limit at the time of commitment shall be used.

(iii) The Tracking Ramp Limited Desired MW (power) calculations in Tariff, Attachment K-Appendix, section 3.2.3(e-1)(i) and (ii) above will continue until the resource goes offline; however, if a generation resource trips or is taken offline at the request of the Market Seller prior to the later of the end of the Day-ahead Energy Market commitment or the end of the Minimum Run Time, the values will continue to be calculated per the calculations defined above until the later of the end of the Day-ahead Energy Market commitment or the end of the Minimum Run Time.

Further, once the Office of the Interconnection releases a generation resource to go offline, provided that the resource actually goes offline following such direction, the Tracking Ramp Limited Desired MW shall be calculated using only the ramp down parameters such that the Tracking Ramp Limited Desired MW is incrementally ramped down to its minimum output, irrespective of the real-time LMP. During this time period, the

unadjusted Tracking Ramp Limited Desired MW (power) will equal the Tracking Ramp Limited Desired MW (power) unless the resource has been manually dispatched offline, in which case the unadjusted Tracking Ramp Limited Desired MW (power) will continue as specified above in Tariff, Attachment K-Appendix, section 3.2.3(e-1)(ii) until the manual dispatch instruction ends.

TRLD MW_t (power) =

Max (TRLD MW_{t-1} – Down $Ramp_t$, Tracking Desired Economic $Minimum_t$)

Where Down Ramp = Decrease in MW utilizing the resource's down ramp rate parameter.

(iv) The Tracking Ramp Limited Desired MW (power) and unadjusted Tracking Ramp Limited Desired MW (power) metrics will be converted to the Tracking Ramp Limited Desired MWh (energy) metrics that shall be used in the calculation of balancing Energy Make Whole credits and generator deviations. For all Real-time Settlement Intervals prior to the start time of the Tracking Ramp Limited Desired MW (power) calculations, t_0 as defined above, both the Tracking Ramp Limited Desired MWh (energy) and the unadjusted Tracking Ramp Limited Desired MWh (energy) shall be equal to the resource's Actual MWh for that Real-time Settlement Interval. For purposes of this section, Actual MWh equals the Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Tariff, Attachment K-Appendix, section 3.1A and parallel provisions in Operating Agreement, Schedule 1, section 3.1A.

For each Real-time Settlement Interval after the Office of the Interconnection releases a generation resource to go offline and the resource's Actual MWh is below the minimum operating limit, the Tracking Ramp Limited Desired MWh (energy) and the unadjusted Tracking Ramp Limited Desired MWh (energy) shall be equal to Actual MWh of the resource.

For all other Real-time Settlement Intervals, the Tracking Ramp Limited Desired MWh (energy) shall equal the expected energy produced between the start of the Real-time Settlement Interval and the end of the Real-time Settlement Interval based on the Tracking Ramp Limited Desired MW (power) at the start and at the end of the Real-time Settlement Interval and the resource's ramping capability, as further described in the PJM Manuals. The unadjusted Tracking Ramp Limited Desired MWh (energy) shall equal the expected energy produced between the start of the Real-time Settlement Interval and the end of the Real-Time Settlement Interval based on the unadjusted Tracking Ramp Limited Desired MW (power) at the start and at the end of the Real-time Settlement Interval and the resource's ramping capability, as further described in the PJM Manuals.

(v) The Tracking Ramp Limited Desired MW (power) and MWh (energy) values described above in subsections Tariff, Attachment K-Appendix, section 3.2.3(e-1)(i) and (ii), as may be qualified by (iii), and (iv) of this section may be further adjusted as described in the PJM Manuals to account for instances where the Office of the Interconnection is

unable to dispatch the system using the real-time security constrained economic dispatch system and/or where the real-time security-constrained economic dispatch application is providing dispatch signals inconsistent with the resource's offer data, or other abnormal dispatch scenarios.

(e-2) For generating resources, balancing Energy Make Whole credits received pursuant to this section shall be equal to the lesser of the Tracking Balancing Energy Make Whole Credit, as calculated in Step 1 below in Tariff, Attachment K-Appendix, section 3.2.3(e-2)(i), and the Actual Balancing Energy Make Whole Credit, as calculated in Step 2 below in Tariff, Attachment K-Appendix, section 3.2.3(e-2)(ii), for each Segment in the Operating Day, except as provided in this Tariff, Attachment K-Appendix, section 3.2.3(m). Balancing Energy Make Whole credits for Economic Load Response Participant resources shall be equal to the credits as determined in Tariff, Attachment K-Appendix, section 3.3.A.

(i) Step 1: Calculate Tracking Balancing Energy Make Whole credit for the Segment using Tracking Ramp Limited Desired MWh.

Tracking Balancing Energy Make Whole Credit = A – B

Where
$A = -1 \times \sum_t$ Tracking Balancing Net Revenue$_t$
Where t = the eligible Real-time Settlement Intervals in the applicable Segment

B = Day-ahead Energy Make Whole Credit as determined pursuant to section 3.2.3(b) if the Segment is the first Segment. For all other Segments, B = 0.

Tracking Balancing Energy Make Whole Credit shall not be less than zero.

The Tracking Balancing Net Revenue for each Real-time Settlement Interval in the Segment shall be calculated in accordance with the following equation:

Tracking Balancing Net Revenue$_t$ = (DA Revenue$_t$ + Balancing Revenue$_t$ + Other Market Revenue$_t$ + Opportunity Cost Owed$_t$) - Real-time Cost$_t$

Where
t = the Real-time Settlement Interval

DA Revenue = Day-ahead Energy Market Revenue for the Real-time Settlement Interval in accordance with the following equation:
Day-ahead Scheduled MWh × Day-ahead LMP

Balancing Revenue = Balancing Energy Market Revenue in accordance with the following equation:
(Tracking Ramp Limited Desired MWh ─ Day-ahead Scheduled MWh) × Real-time LMP ─ Company Responsible Negative Revenues

Where: Company Responsible Negative Revenues = any negative balancing revenues in excess of the Day-ahead Energy Market revenue that results from the Market Participant's actions reducing the resource's flexibility as further specified in the PJM Manuals. This is calculated as:

MW unavailable due to limited flexibility × Min (Day-ahead LMP ─ Real-Time LMP, 0)

Other Market Revenue = SR + SecR + NSR + Reactive + LOC + Reg

Where
SR = any potential credits for providing Synchronized Reserve determined in accordance with the credit calculations in Tariff, Attachment K-Appendix, section 3.2.3A(b) less the resource's Synchronized Reserve offer price, in dollars, included in the resource's Synchronized Reserve potential lost opportunity cost credit in Tariff, Attachment K-Appendix, section 3.2.3A(f)(iv).

SecR = any potential credits for providing Secondary Reserve determined in accordance with the credit calculations in Tariff, Attachment K-Appendix, section 3.2.3A.01(b)

NSR = any amounts credited for providing Non-Synchronized Reserve as specified in Tariff, Attachment K-Appendix, section 3.2.3A.001(b)

Reactive = any potential credits for providing Reactive Services determined in accordance with the credit calculations in Tariff, Attachment K-Appendix, section 3.2.3B

LOC = any potential lost opportunity cost credits determined in Tariff, Attachment K-Appendix, sections 3.2.3(f) – 3.2.3(f-6).

Reg = any potential Regulation opportunity cost amounts determined in accordance with the calculations for use in settlements in Tariff, Attachment K-Appendix, section 3.2.2.

Opportunity Cost Owed = the sum of the potential opportunity costs owed for Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve as determined in accordance with Sections 3.2.3A(f)(iv), 3.2.3A.001(d)(iii) and 3.2.3A.01(f)(iv), respectively.

For the purposes of the above Other Market Revenue and Opportunity Cost Owed calculations, the potential credits and costs are determined using the calculations referenced above and the assumption that the resource was increased or decreased from

the unadjusted Tracking Ramp Limited Desired MWh in order to provide the assignment or PJM directed MW as further described in the PJM Manuals.

Real-time Cost = (Incremental Offer + No Load Cost + Start-Up Cost)
Where

Incremental Offer = Real-time incremental energy offer, in dollars, based on the area under the incremental energy offer curve calculated using the Tracking Ramp Limited Desired MWh

No Load = Real-time No-load Cost

Start-Up = Real-time Start-Up Cost, if it is a Real-time Settlement Interval in the first Segment

The offer used for calculating Real-time Cost shall be the lesser of the Committed Offer or Final Offer based on the offer with the lowest total cost for the hour.

The above Balancing Revenue and Real-time Cost calculations shall be further modified for Real-time Settlement Intervals preceding the start of the commitment for generation resource types with no soak process in the Start-up Cost by capping the Tracking Ramp Limited Desired MWh (energy) at the minimum operating limit for such interval.

The above Balancing Revenue and Real-time Cost calculations shall be reduced by the costs incurred and revenues received in the applicable Real-time Settlement Intervals for generation resource types with a soak process in the Start-up Cost when the Tracking Ramp Limited Desired MWh (energy) indicate the unit is not dispatchable by the Office of the Interconnection during a Real-time Settlement Interval when it was scheduled to be dispatchable since those costs and revenues may already be included in the Start-Up Cost as further defined in the PJM Manuals.

During Real-time Settlement Intervals where a Flexible Resource is self-scheduled and was committed by the Office of the Interconnection in the Day-ahead Energy Market for the same Real-time Settlement Interval, the above calculation will use the Tracking Balancing Net Revenues that the resource would have received if it had followed PJM real-time commitment instructions and remained offline; provided that if the unit is taken over by company to run as self-scheduled prior to the Minimum Run Time of a pool scheduled commitment elapsing, this shall only apply to those Real-time Settlement Intervals beyond the Minimum Run Time.

(ii) Step 2: Calculate balancing Energy Make Whole credits for the Segment using Actual MWh.

Actual Balancing Energy Make Whole Credit = A – B

Where
A = -1 × $\sum_t$ Actual Balancing Net Revenue$_t$
Where t = the eligible Real-time Settlement Intervals in the applicable Segment
B = Day-ahead Energy Make Whole Credit as determined pursuant to section 3.2.3(b) if the Segment is the first Segment; else, 0

Actual Balancing Energy Make Whole Credit shall not be less than zero.

The Actual Balancing Net Revenue for each Real-time Settlement Interval in the Segment shall be calculated in accordance with the following equation. For purposes of this section, the Actual MWh equals the Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Tariff, Attachment K-Appendix, section 3.1A.

Actual Balancing Net Revenue$_t$ = (DA Revenue$_t$ + Balancing Revenue$_t$ + Other Market Revenue$_t$) - Real-time Cost$_t$

Where
t = the Real-time Settlement Interval

DA Revenue = Day-ahead Energy Market Revenue for the Real-time Settlement Interval in accordance with the following equation:
Day-ahead Scheduled MWh × Day-ahead LMP

Balancing Revenue = Balancing Energy Market Revenue for the Real-time Settlement Interval in accordance with the following equation:

(Actual MWh – Day-ahead Scheduled MWh) × Real-time LMP ― Company Responsible Negative Revenues

Where: Company Responsible Negative Revenues = any negative balancing revenues in excess of the DA revenue based on the Market Participant's actions reducing flexibility as further specified in the PJM Manuals. This is calculated as:

MW unavailable due to limited flexibility × Min (Day-ahead LMP ― Real-Time LMP, 0)

Other Market Revenue = SR + SecR + NSR + Reactive + LOC + Reg

Where:
SR = any amounts credited for providing Synchronized Reserve equal to the credits as determined in Tariff, Attachment K-Appendix, section 3.2.3A(b) less the resource's Synchronized Reserve offer price, in dollars,

included in the resource's Synchronized Reserve lost opportunity cost credit calculation in Tariff, Attachment K-Appendix, section 3.2.3A(f)(iv)

SecR = any amounts credited for providing Secondary Reserve as determined in Tariff, Attachment K-Appendix, section 3.2.3A.01 (b)

NSR = any amounts credited for providing Non-Synchronized Reserve as determined in Tariff, Attachment K-Appendix, section 3.2.3A.001(b)

Reactive = any amounts credited for providing Reactive Services as determined in Tariff, Attachment K-Appendix, section 3.2.3B

LOC = any lost opportunity costs credits as determined in Tariff, Attachment K-Appendix, sections 3.2.3(f) – 3.2.3(f-6); and

Reg =any Regulation opportunity cost amounts as calculated for purposes of settlements in Tariff, Attachment K-Appendix, section 3.2.2

Real-time Cost = (Incremental Offer + No Load + Start-Up)

Incremental Offer = Real-time incremental energy offer, in dollars, based on the area under the incremental energy offer curve calculated using the Actual MWh

No Load = Real-time No-load Cost

Start-Up = Real-time Start-Up Cost, if it is within the first Segment

The offer used for calculating Real-time Cost shall be the Final Offer for the hour.

The above Balancing Revenue and Real-time Cost calculations shall be reduced by the costs incurred and revenues received in the applicable Real-time Settlement Intervals for generation resource types with a soak process in the Start-up Cost when the Actual MWh indicate the resource is not dispatchable by the Office of the Interconnection during a Real-time Settlement Interval when it was scheduled to be dispatchable by the Office of the Interconnection since those costs and revenues may already be included in the Start-Up Cost as further defined in the PJM Manuals.

The above Balancing Revenue and Real-time Cost calculation shall be further modified for Real-time Settlement Intervals preceding the start of the commitment for generation resource types with no soak process in the Start-up Cost, by capping the Actual MWh at the minimum operating limit for each such interval.

(iii) In the event of a real-time Market Suspension, if the Office of the Interconnection and the Market Monitoring Unit determine that the generation resource was not following dispatch instructions, the generation resource shall be ineligible for balancing Energy Make Whole credits. If the generation resource is eligible during a real-time Market

Suspension, the balancing Energy Market Whole credit shall be equal to the actual balancing Energy Make Whole credit, as determined in subsection 3.2.3(e-2)(ii) of this section.

(iv) A price-sensitive pool-scheduled import transaction shall receive balancing Energy Make Whole credits equal to the positive difference between a transaction's offer, and the total value of the transaction's energy in the Day-ahead Energy Market plus any credit or charge for quantity deviations from the Day-ahead Energy Market at the real-time LMP(s) applicable to the sink of the transaction summed over all Real-time Settlement Intervals in the Operating Day.

(f) A Market Seller of a unit not defined in subsection (f-1), (f-2), or (f-4) hereof (or self-scheduled, if operating according to Tariff, Attachment K-Appendix, section 1.10.3(c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the LOC Deviation times (B) the Locational Marginal Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C. A Market Seller of a unit defined in subsection (f-1), (f-2), (f-3), (f-4), or (f-5) that is reduced using a generator output constraint to honor a stability limitation is not eligible for credits under this section 3.2.3(f) for the MWh reduction associated with honoring the stability limit. If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.11.6, where the suspension is greater than twenty-four (24) consecutive hours, resources will not be compensated for lost opportunity costs.

(f-1) With the exception of Market Sellers of Flexible Resources that submit a Real-time Offer greater than their resource's Committed Offer in the Day-ahead Energy Market, a Market Seller of a Flexible Resource shall be compensated for lost opportunity cost, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described in section 3.2.3 (f).

(ii) If the unit is scheduled to produce energy in the Day-ahead Energy Market for a Day-ahead Settlement Interval, but the unit is not called on by the Office of the Interconnection and does not operate in the corresponding Real-time Settlement

Interval(s), then the Market Seller shall be credited in an amount equal to the higher of:

1) the product of (A) the amount of megawatts committed in the Day-ahead Energy Market for the generating unit, and (B) the Real-time Price at the generation bus for the generating unit, minus the sum of (C) the Total Lost Opportunity Cost Offer plus No-load Costs, plus (D) the Start-up Cost, divided by the Real-time Settlement Intervals committed for each set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market. This equation is represented as (A*B) - (C+D). The startup cost, (D), shall be excluded from this calculation if the unit operates in real time following the Office of the Interconnection's direction during any portion of the set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market, or

2) the Real-time Price at the unit's bus minus the Day-ahead Price at the unit's bus, multiplied by the number of megawatts committed in the Day-ahead Energy Market for the generating unit.

(f-2) A Market Seller of a hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Tariff, Attachment K-Appendix, section 1.10.3(c) hereof), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-4) A Market Seller of a wind or solar generating unit, Hybrid Resource or Energy Storage Resource Model Participant that is pool-scheduled or self-scheduled, has SCADA capability to transmit and receive instructions from the Office of the Interconnection, has provided data and established processes to follow PJM basepoints pursuant to the requirements

for wind or solar generating units, Hybrid Resource or Energy Storage Resource Model Participant as further detailed in this Agreement, the Tariff and the PJM Manuals, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the LOC Deviation times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C. An Energy Storage Resource Model Participant or a Hybrid Resource instructed to increase charging at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, shall be compensated for the increase in charging in the same manner as provided in sections 3.2.3(e). A unit in the Energy Storage Resource Participation Model or a Hybrid Resource instructed to reduce charging at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, is not eligible for compensation under section 3.2.3(f-4).

(f-5) If a Market Participant of an Energy Storage Resource Model Participant or a Hybrid Resource believes that the above calculations in this section 3.2.3 do not accurately compensate the Market Participant for opportunity costs associated with following PJM manual dispatch instructions to modify a unit's charging or discharging due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Participant will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Participant. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Participant accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-6) (i) A Market Seller of a pool-scheduled resource or a dispatchable self-scheduled resource shall receive Dispatch Differential Lost Opportunity Cost credits as calculated under subsection (iv) below if the resource is dispatched to provide energy in the Real-time Energy Market, provided such resource is not committed to provide real-time ancillary services (Regulation, reserves, reactive service) or instructed to reduce or suspend output due to a transmission constraint or other reliability issue pursuant to Tariff, Attachment K-Appendix, section 3.2.3(f-1) through Tariff, Attachment K-Appendix, section (f-4).

(ii) PJM will calculate the revenue above cost for the pricing run for each Real-time Settlement Interval in accordance with the following equation:

(A x B) - C

Where:

A = the resource's expected output level based on its resource parameters at the Real-time Price at the applicable pricing point;

B = the Real-time Price at the applicable pricing point; and

C = the sum of the resource's Real-time Energy Market offer integrated under the Final Offer for the resource's expected output level based on its resource parameters at the Real-time Price at the applicable pricing point.

(iii) PJM will calculate the revenue above cost for the dispatch run for each Real-time Settlement Interval in accordance with the following equation:

(greater of A and B) – (lesser of C and D)

Where:

A = the product of the amount of megawatts of energy dispatched in the Real-time Energy Market dispatch run for the resource in that Real-time Settlement Interval and the Real-time Price at the applicable pricing point;

B = the product of the amount of megawatts of energy the resource actually provided in that Real-time Settlement Interval and the Real-time Price at the applicable pricing point;

C = the resource's Real-time Energy Market offer integrated under the Final Offer for the amount of megawatts dispatched in the Real-time Energy Market dispatch run;

D = the resource's Real-time Energy Market offer integrated under the Final Offer for the amount of megawatts the resource actually provided in that Real-time Settlement Interval.

(iv) The Dispatch Differential Lost Opportunity Cost credit shall equal the greater of (A) the difference between the revenue above cost based on the pricing run determined in subsection (f-6)(ii) and the revenue above cost based on the dispatch run determined in subsection (f-6)(iii) or (B) zero.

(v) For each hour in an Operating Day, the total cost of the Dispatch Differential Lost Opportunity Cost credits shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load ((a) net of operating Behind The Meter Generation, but not to be less than zero; and (b) excluding Direct Charging Energy) in the PJM Region, served under Network Transmission Service, in megawatt-hours; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours but not including its bilateral transactions that are Dynamic Transfers to load

outside the PJM Region pursuant to Tariff, Attachment K-Appendix, section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(g) The sum of the foregoing credits in Tariff, Attachment K-Appendix, section 3.2.3(f) through Tariff, Attachment K-Appendix, section 3.2.3(f-5), plus any cancellation fees paid in accordance with Tariff, Attachment K-Appendix, section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, plus any balancing Energy Make Whole Credits paid to pool-scheduled import transactions, less any payments received from another Control Area for energy uplift shall be allocated to each Market Participant's pro rata share of the daily total of hourly deviations in the RTO region, determined pursuant to Tariff, Attachment K-Appendix, section 3.2.3(h). If the Office of the Interconnection declares a Market Suspension, per Tariff, Attachment K-Appendix, section 1.11.6, the Office of the Interconnection shall allocate the charges to the pro rata share of the sum of its (i) deliveries of energy to load ((a) net of operating Behind The Meter Generation, but not to be less than zero; and (b) excluding Direct Charging Energy) in the PJM Region, served under Network Transmission Service, in megawatt-hours; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Tariff, Attachment K-Appendix, section 1.12.

(h) Each Market Participant's daily total of hourly deviations are determined in accordance with the following equation:

$$\sum_h (A + B + C)$$

Where:

h = the hours in the applicable Operating Day;

A = For each Real-time Settlement Interval in an hour, the sum of the absolute value of the withdrawal deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy withdrawals (net of operating Behind The Meter Generation) in the Real-time Energy Market, except as noted in subsection (h)(ii) below and in the PJM Manuals divided by the number of Real-time Settlement Intervals for that hour. The summation of each Real-time Settlement Interval's withdrawal deviation in an hour will be the Market Participant's total hourly withdrawal deviations. Market Participant bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Tariff, Attachment K-Appendix, section 1.12 are not included in the determination of withdrawal deviations;

B = For each Real-time Settlement Interval in an hour, the sum of the absolute value of generation deviations (in MW and not including deviations in Behind The Meter Generation) as determined in subsection (o) divided by the number of Real-time Settlement Intervals for that hour;

C = For each Real-time Settlement Interval in an hour, the sum of the absolute value of the injection deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy injections in the Real-time Energy Market divided by the number of Real-time Settlement Intervals for that hour. The summation of the injection deviations for each Real-time Settlement Interval in an hour will be the Market Participant's total hourly injection deviations. The determination of injection deviations does not include generation resources.

The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Tariff, Attachment K-Appendix, section 3.1A shall be used in determining the real-time withdrawal deviations, generation deviations and injection deviations under this subsection (h).

The foregoing notwithstanding, netting deviations shall be allowed for each Real-time Settlement Interval in accordance with the following provisions:

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions, which include the components referenced in Tariff, Attachment K-Appendix, section 3.2.3(d) regarding the cost of Energy Make Whole credits in the Day-ahead Energy Market, at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

(iv) Bilateral transactions inside the PJM Region, as defined in Tariff, Attachment K-Appendix, section 1.7.10, will not be included in the determination of supply or demand deviations.

Deviations as calculated above shall be deviations in the RTO region and shall be subject to charges for the RTO region determined in accordance with Tariff, Attachment K-Appendix, section 3.2.3(q)(iii). Furthermore, deviations that occur within a single Zone shall be associated with the Eastern or Western region, as defined in Tariff, Attachment K-Appendix, section 3.2.3(q) below, and shall be subject to charges determined for such region in accordance with Tariff, Attachment K-Appendix, section 3.2.3(q)(iii). Deviations at a hub shall be associated with the Eastern or Western region if all the buses that define the hub are located in the region. Deviations at an Interface Pricing Point shall be associated with whichever region, the Eastern or

Western region, with which the majority of the buses that define that Interface Pricing Point are most closely electrically associated. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to charges determined for such region in accordance with Tariff, Attachment K-Appendix, section 3.2.3(q)(iii). Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by buses that are wholly contained within the same Zone.

(i) At the end of each Operating Day, Market Sellers shall be credited for Condense Startup Cost and Condense Energy Use times the real-time LMP for synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in section 3.2.3(i) shall be the cost of energy uplift for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for the PJM Region.

(k) The cost of energy uplift for synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load ((a) net of operating Behind The Meter Generation, but not to be less than zero; and (b) excluding Direct Charging Energy) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Tariff, Attachment K-Appendix, section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared ("Maximum Generation Emergency Alert"); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the Energy Make Whole credit otherwise provided by section 3.2.3.(b) or section 3.2.3(e) in connection with market-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as "MaxGen Conditions"). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Operating Agreement, Schedule 2, in which case subsections (m) and (n) shall not apply to such offer; provided,

however, that such offer must be submitted in accordance with the deadlines in Tariff, Attachment K-Appendix, section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Tariff, Attachment K-Appendix, section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Tariff, Attachment K-Appendix, section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh and greater than the Market Seller's lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Energy Make Whole. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Energy Make Whole for such Operating Day pursuant to section 3.2.3(e) plus the Real-time Energy Market revenues for the Real-time Settlement Intervals that the offer is economic divided by the megawatt hours of energy provided during the Real-time Settlement Intervals that the offer is economic. The Real-time Settlement Intervals that the offer is economic shall be: (i) the Real-time Settlement Intervals that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the Real-time Settlement Intervals in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any Real-time Settlement Intervals required due to the Minimum Run Time or other operating constraint of the unit, and (iii) for any unit with a Minimum Run Time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price for a market-based offer is greater than $1,000/MWh and greater than the Market Seller's lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Energy Make Whole. If notice of a MaxGen Condition is provided after 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Energy Make Whole determined in accordance with section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Energy Make Whole determined in accordance with section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Energy Make Whole for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when

such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Energy Make Whole for such Operating Day pursuant to section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Energy Make Whole payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) All generation resources shall be assessed deviations in accordance with the calculations described below and in the PJM Manuals.

Generation resource deviations are calculated as the difference between a resource's Actual MWh, (which for purposes of this section is defined as the Revenue Data for Settlements), and Tracking Ramp Limited Desired MWh for each Real-time Settlement Interval except for the scenarios where day-ahead scheduled MWh are used in the calculation as defined below.

A generation resource shall not be assessed deviations for the Real-time Settlement Interval if its deviation percentage <= 0.10 (10 percent).

$$Deviation\ Percentage = Abs\ [1 - \frac{Actual\ MWh}{Tracking\ Ramp\ Limited\ Desired\ \ MWh}\ ]$$

If the Actual MWh is equal to zero, the deviation percentage is equal to 1 (100 percent).

Generation resource deviations are calculated as the difference between a resource's Real-time Settlement Interval MWh and day-ahead scheduled MWh, rather than Tracking Ramp Limited Desired MWh, when a resource is non-dispatchable for any Real-time Settlement Interval. For purposes of this provision, a resource will be considered non-dispatchable when any of the following conditions occur:

- The generation resource is not dispatchable in the Day-ahead Energy Market and is not dispatchable in the Real-time Energy Market. For purposes of the generation resource deviation calculation, not dispatchable is defined as intervals when the minimum operating limit is equal to the maximum operating limit, or intervals when a generation resource elects to provide a fixed output using the fixed generation parameter, or other not dispatchable processes as defined in the PJM Manuals. All hydro resources are considered non-dispatchable unless operated as a dispatchable resource by the Office of the Interconnection.
- The self-scheduled generation resource is not dispatchable due to a limited dispatchable range. A dispatchable range is considered limited when the following equation is true:
    - Abs(maximum operating limit – minimum operating limit) <= 10% of Abs(minimum operating limit).

- The dispatchable self-scheduled generation resource has a Tracking Ramp Limited Desired MWh <= the minimum operating limit, except when the resource is desired at that level due to a Minimum Generation Emergency declaration or event.
- A generation resource is online and Tracking Ramp Limited Desired MWh is unable to be calculated due to unavailable schedules or offer parameters.

A generation resource shall not be assessed deviations for the Real-time Settlement Interval if its day-ahead deviation percentage is <= 0.05 (5%).

$$Day-ahead\ Deviation\ Percentage = Abs\ [1 - \frac{Actual\ MWh}{Day-ahead\ Scheduled\ MWh}\ ]$$

If the Actual MWh is equal to zero, the day-ahead deviation percentage is equal to 1 (100 percent).

A generation resource shall not be assessed deviations in a Real-time Settlement Interval if any of the following conditions occur for that interval:

- The resource is assigned pool-scheduled Regulation.
- The resource is assigned pool-scheduled Real-time Synchronized Reserves as a synchronous condenser.
- The resource is assigned pool-scheduled Real-time Secondary Reserves as a synchronous condenser.
- The resource is assigned pool-scheduled Real-time Non-Synchronized Reserves.
- The resource is assigned Real-time Synchronized Reserves and responded during a Synchronized Reserve Event.
- Flexible Resources that are committed in the Day-ahead Energy Market and not committed by the Office of the Interconnection in the Real-time Energy Market and the resource is offline.
- The resource is manually dispatched by the Office of the Interconnection and the manual instruction is not reflected in the Tracking Ramp Limited Desired MWh.

Deviations of generation resources with multiple units located at a single bus shall be netted for each Real-time Settlements Interval as described in Tariff, Attachment K-Appendix, section 3.2.3(h)(i).

If a resource has an hourly average of the absolute value of generator deviations that is less than 5 MWh, then the resource shall not be assessed deviations for each Real-time Settlement Interval in that hour. This calculation shall be done after netting is applied, where applicable.

For the purpose of this section 3.2.3(o), a generation resource is considered to be following dispatch if it is not assessed deviations or has a deviation equal to zero in a Real-time Settlement Interval, as determined above and prior to any netting pursuant to section 3.2.3(h)(i) or for hourly averages pursuant to this section

(o-1) Dispatchable Economic Load Response Participant resources that follow dispatch shall not be assessed deviations. Economic load reduction resources that do not follow dispatch

shall be assessed deviations as described in this subsection and as further specified in the PJM Manuals.

The Desired MW quantity for such resources for each hour shall be the hourly integrated MW quantity to which the load reduction resource was dispatched for each hour (where the hourly integrated value is the average of the dispatched values as determined by the Office of the Interconnection for the resource for each hour).

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual reduction quantity) and charged as defined in Tariff, Attachment K-Appendix, section 3.3A. For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined in Tariff, Attachment K-Appendix, section 3.3A. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall apply any balancing Energy Make Whole credits determined pursuant to Tariff, Attachment K-Appendix, section 3.2.3(e-2), except those associated with the scheduling of units for Black Start Service or testing of Black Start Service units as provided in Tariff, Schedule 6A, to deviations determined pursuant to section 3.2.3(h) or real-time load plus exports depending on whether the underlying balancing Energy Make Whole credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Energy Make Whole credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Energy Make Whole credits, identified as reliability analysis credits for deviations, shall be allocated to deviations determined pursuant to Tariff, Attachment K-Appendix, section 3.2.3(h).

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Energy Make Whole credits, identified as reliability analysis credits for reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Energy Make Whole credits shall be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(p)(i)(A) and 3.2.3(p)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Energy Make Whole credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Energy Make Whole credits, identified as real-time credits for reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceeds the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (real-time credits for reliability or real-time credits for deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Tariff, Attachment K-Appendix, section 3.2.3(p)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Energy Make Whole credits, identified as real-time credits for deviations, shall be allocated to deviations determined pursuant to Tariff, Attachment K-Appendix, section 3.2.3(h).

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in Tariff, Attachment K-Appendix, sections 3.2.3(p)(i) and (p)(ii).

The costs associated with scheduling of units for Black Start Service or testing of Black Start Service units shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zonal load or non-Zonal load, as determined in accordance with the formulas contained in Tariff, Schedule 6A.

(q) (i) Balancing Energy Make Whole credits for reliability or deviations as determined in Tariff, Attachment K-Appendix, section 3.2.3(p) shall be assigned to the Eastern or Western region if the credit paid to the generator is due

to transmission constraints that occur on transmission system capacity equal to or less than 345kv. Balancing Energy Make Whole credits for reliability or deviations not assigned to the Eastern or Western region shall be assigned to the RTO region. For the purposes of this section, the Western region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, DEOK, EKPC, OVEC transmission Zones, and the Eastern region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones.

(ii) The total balancing Energy Make Whole credits for reliability in each region shall be allocated as charges to each Market Participant's pro rata share of real-time load plus export transactions in such region. For purposes of this Tariff, Attachment K-Appendix, section 3.2.3(q), a Market Participant's real-time load plus export transactions shall be equal to the daily total of (i) real-time deliveries of energy to load in the relevant region ((a) net of operating Behind The Meter Generation, but not to be less than zero; and (b) excluding Direct Charging Energy), served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) real-time deliveries of energy sales from within the PJM Region to load outside the PJM Region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Tariff, Attachment K-Appendix, section 1.12.

(iii) The total balancing Energy Make Whole credits for deviations in the Eastern region and the Western region shall be allocated as charges to each Market Participant's pro rata share of the daily total of hourly deviations in the relevant region as determined pursuant to Tariff, Attachment K-Appendix, section 3.2.3(h). The total balancing Energy Make Whole credits for deviations in the RTO region plus the total credits as determined in Tariff, Attachment K-Appendix, section 3.2.3(g) shall be allocated as charges to each Market Participant's pro rata share of the daily total of hourly deviations in the RTO region as determined pursuant to Tariff, Attachment K-Appendix, section 3.2.3(h). If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.11.6, the Office of the Interconnection shall allocate deviation charges to the ratio share of real-time load plus export transactions pursuant to Tariff, Attachment K-Appendix, section 3.2.3(q)(ii).

(q-1) (i) Regional balancing uplift rates shall be determined in accordance with the following provisions:

The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western regions. Regional adder rates for reliability shall be equal to the total balancing Energy Make Whole credits for reliability in the region divided by the total real-time load plus export transactions in the relevant region in accordance with Tariff, Attachment K-Appendix, section 3.2.3(q)(ii). Whether

the underlying credits are designated as reliability or deviation charges shall be determined in accordance with Tariff, Attachment K-Appendix, section 3.2.3(p).

Regional adder rates for deviations shall be equal to the total balancing Energy Make Whole credits for deviations in the region divided by the daily total of hourly deviations in the relevant region in accordance with Tariff, Attachment K-Appendix, section 3.2.3(q)(iii).

(ii) The Office of the Interconnection shall calculate RTO balancing uplift rates. RTO balancing uplift rates for reliability shall be equal to the total balancing Energy Make Whole credits for reliability in the RTO region divided by the total real-time load plus export transactions in the RTO region in accordance with section (q)(ii). RTO balancing uplift rates for deviations shall be equal to the total balancing Energy Make Whole credits for deviations in the RTO region plus the total credits as determined in Tariff, Attachment K-Appendix, section 3.2.3(g) divided by the daily total of hourly deviations in the RTO region as determined pursuant to Tariff, Attachment K-Appendix, section 3.2.3(h). Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Tariff, Attachment K-Appendix, section 3.2.3(p).

(iii) Reliability and deviation regional balancing uplift rates shall be determined by summing the relevant RTO balancing Energy Make Whole rates and regional adder rates.

(r) Market Sellers that incur incremental operating costs for a generation resource that are either greater than $1,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Operating Agreement, Schedule 2 and PJM Manual 15, but are not verified at the time of dispatch of the resource under Tariff, Attachment K-Appendix, section 6.4.3, or greater than $2,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Operating Agreement, Schedule 2, and PJM Manual 15, will be eligible to receive credit for Energy Make Whole upon review of the Market Monitoring Unit and the Office of the Interconnection, and approval of the Office of the Interconnection. Market Sellers must submit to the Office of the Interconnection and the Market Monitoring Unit all relevant documentation demonstrating the calculation of costs greater than $2,000/MWh, and costs greater than $1,000/MWh which were not verified at the time of dispatch of the resource under Tariff, Attachment K-Appendix, section 6.4.3. The Office of the Interconnection must approve any Energy Make Whole credits paid to a Market Seller under this subsection (r).

3.2.3A Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour

("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant's hourly Synchronized Reserve Obligation shall be adjusted by any Synchronized Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Synchronized Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Synchronized Reserve as defined in sections 3.2.3A(b)(i) and (ii) below.

(b) A resource supplying Synchronized Reserve at the direction of the Office of the Interconnection shall be credited as follows:

i) Credits for Synchronized Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Synchronized Reserve by the Office of the Interconnection or self-scheduled in the Day-ahead Synchronized Reserve Market shall be equal to the product of the Day-ahead Synchronized Reserve Market Clearing Price multiplied by the megawatt amount of Synchronized Reserve such resource is assigned to provide.

ii) Credits for Synchronized Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Synchronized Reserve by the Office of the Interconnection or self-scheduled in the Real-time Synchronized Reserve Market shall be determined for each operating hour based on the sum of their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$$\sum_i ((A - B) * C)$$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Synchronized Reserve from that resource assigned by the Office of the Interconnection or self-scheduled in the Real-time Synchronized Reserve Market. The megawatt value is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval where there is not a Synchronized Reserve event;

B = For each Real-time Settlement Interval, the megawatts of Synchronized Reserve from that resource assigned by the Office of the Interconnection or self-scheduled in the Day-ahead Synchronized Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Synchronized Reserve Market Clearing Price.

If a Synchronized Reserve Event is initiated by the Office of the Interconnection and the Economic Load Response Participant resource reduced its load in response to the event, the resource shall be eligible to receive a credit for the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

iii) Pool-scheduled resources shall be credited a Synchronized Reserve lost opportunity cost credit, where positive, as described in subsection (f)(iv) below.

(c) [Reserved for future use]

(d) Synchronized Reserve Market Clearing Prices

(i) For the Day-ahead Synchronized Reserve Market, the Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Synchronized Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for Synchronized Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Synchronized Reserve offer prices and opportunity costs and the Operating Reserve Demand Curve for Synchronized Reserve for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Synchronized Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute and (B) the price of serving the next increment of demand for Primary Reserve and 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.10.8(d), Day-ahead Synchronized Reserve Market Clearing Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and Day-ahead Synchronized Reserve Market Clearing Price of zero dollars per megawatt-hour and all settlements will be based on the Real-time Synchronized Reserve market quantities and prices as determined pursuant to subsection (d)(ii) hereof.

(ii) For the Real-time Synchronized Reserve Market, the Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for Synchronized Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Synchronized Reserve offer prices and opportunity costs and the Operating Reserve Demand Curve for Synchronized Reserve for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Synchronized Reserve for

any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute and (B) the price of serving the next increment of demand for Primary Reserve and 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, and the Office of the Interconnection is not assigning Synchronized Reserves, then the Synchronized Reserve Market Clearing Price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, where the real-time Market Suspension is less than or equal to six (6) consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Synchronized Reserves, then the Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Synchronized Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than six (6) consecutive hours but less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating Days, and there are cleared Day-ahead Synchronized Reserve Market Clearing Prices for the affected Operating Day, then the Real-time Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the Day-ahead Synchronized Reserve Market Clearing Prices for each corresponding hour. If no such Day-ahead Synchronized Reserve Market Clearing Prices exist, then the Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Synchronized Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than twenty-four (24) consecutive hours, and the Office of the Interconnection is assigning Synchronized Reserves, the Office of the Interconnection will set the Synchronized Reserve Market Clearing Price to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period. Resources will be compensated for lost opportunity cost per subsection (f) hereof using the energy price as determined in Operating Agreement, Schedule 1, section 2.5.2.iii. The opportunity cost shall be zero for all resources self-scheduled to provide Synchronized Reserve, synchronous condensers and Economic Load Response Participant resources.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Synchronized Reserve

Market Clearing Price shall be the sum of the Reserve Penalty Factors for the Primary Reserve Requirement, and the Synchronized Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

(iii) The Reserve Penalty Factor for the Minimum Synchronized Reserve Requirement shall be $2,000/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $2,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Reserve Penalty Factor on the Operating Reserve Demand Curves for Synchronized Reserve are warranted for subsequent Delivery Year(s).

(e) (i) For determining the Synchronized Reserve Market Clearing Price in each hour of the Day-ahead Synchronized Reserve Market, the estimated resource-specific opportunity cost for a generation resource or Economic Load Response Participant resource shall be the difference between the Locational Marginal Price at the generation or Economic Load Response Participant resource bus and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) or offer price to reduce energy from the Economic Load Response Participant resource in the PJM Interchange Energy Market when the Locational Marginal Price at the generation or Economic Load Participant resource bus is greater than the offer price for energy from the generation resource or the offer price to reduce energy from the Economic Load Response Participant resource.

However, opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve and for synchronous condensers and for Economic Load Response Participant resources that do not receive a day-ahead commitment to provide energy in the same operating hour in which such resource is committed to provide Synchronized Reserve.

(ii) For determining the Synchronized Reserve Market Clearing Price for each Real-time Settlement Interval in the Real-time Synchronized Reserve Market, the estimated unit-specific opportunity cost for a generation resource that is not a hydroelectric resource shall be the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

For hydroelectric resources, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions, as

defined in the PJM Manuals, and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

The opportunity costs shall be zero for all resources self-scheduled to provide Synchronized Reserve, synchronous condensers and Economic Load Response Participant resources.

(f) (i) In determining the credit under subsection (b) to a generation resource, except a generation resource that is operating as a synchronous condenser, selected to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market, or an Economic Load Response Participant resource that is selected to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market for the same operating hour in which such resource receives a day-ahead commitment to provide energy, the opportunity cost of a resource shall be determined for each operating hour that the Office of the Interconnection requires a resource to provide Synchronized Reserve and shall be in accordance with the following equation:

(A x B) – C

Where:

A = The Day-ahead Locational Marginal Price at the generation bus of the generation resource or the applicable pricing point for the Economic Load Response Participant resource;

B = The deviation of the resource's energy output or load reduction necessary to supply a Day-ahead Synchronized Reserve assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load; and

C = The Day-ahead Energy market offer integrated under the applicable energy offer curve for the resource's energy output or load reduction necessary to provide a Day-ahead Synchronized Reserve Market assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load.

For a generation resource that is operating as a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [Condense

Energy Use multiplied by A] plus [the applicable Condense Startup Cost divided by the number of hours the resource is assigned Synchronized Reserve].

(ii) In determining the credit under subsection (b) to a generation resource, except a generation resource that is operating as a synchronous condenser, selected to provide Synchronized Reserve in the Real-time Synchronized Reserve Market in excess of the resource's Day-ahead Synchronized Reserve Market assignment and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of that generation resource shall be determined for each Real-time Settlement Interval that the Office of the Interconnection requires that generation resource to provide Synchronized Reserve and shall be in accordance with the following equation:

(A x B) - C

Where:

A = The Real-time Locational Marginal Price at the generation bus of the generation resource;

B = The deviation of the generation resource's output necessary to supply Synchronized Reserve in real-time, reduced by the amount of Synchronized Reserve the resource failed to respond during a Synchronized Reserve Event during the Operating Day, in excess of its Day-ahead Synchronized Reserve Market assignment and follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy; and

C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Synchronized Reserve in real-time from the lesser of the generation resource's output necessary to provide a Day-ahead Synchronized Reserve Market assignment or follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [additional Condense Energy Use in excess of day-ahead Condense Energy Use in real-time multiplied by A] plus [any applicable Condense Startup Cost due to additional Condense Startup Cost in real-time in excess of day-ahead Condense Startup Cost allocated to each Real-time Settlement Interval as described in PJM Manuals].

For hydroelectric resources, the unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the real-time Locational Marginal Price at that generation bus multiplied by the additional

megawatts assigned to supply Synchronized Reserve in real-time in excess of its Day-ahead Synchronized Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average real-time Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating multiplied by the additional megawatts assigned to supply the hourly Synchronized Reserve in real-time in excess of its Day-ahead Synchronized Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

(iii) For each Real-time Settlement Interval, a Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in the resource's real-time reserve MW from a day-ahead market assignment in more than one market for that Real-time Settlement Interval, the total Market Revenue Neutrality Offset is allocated to the Synchronized Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Synchronized Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Synchronized Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Synchronized Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Synchronized Reserve assignment decreases due to the resource being self-scheduled to provide energy or Regulation;

(B) A resource reduces its flexibility in real-time such that the resource no longer qualifies to provide Synchronized Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time;

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above; or

(F) A resource increases its Synchronized Reserve offer price in the Real-time Synchronized Reserve Market from its offer price in the Day-ahead Synchronized Reserve Market.

(iv) A Synchronized Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

(A + B + C + D) – (E + F + G + H)

Where:

A = day-ahead Synchronized Reserve offer price times the Synchronized Reserve MW assignment;

B = real-time Synchronized Reserve offer price times the Synchronized Reserve MW assigned in real-time in excess of the Synchronized Reserve MW assigned day-ahead, where the Synchronized Reserve MW assigned is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval where there is not a Synchronized Reserve event;

C = day-ahead opportunity cost as determined in subsection (f)(i) above;

D = real-time opportunity cost as determined in subsection (f)(ii) above;

E = day-ahead clearing price credits as determined in subsection (b)(i) above;

F = real-time clearing price credits as determined in subsection (b)(ii) above less any applicable charges for failure to respond to a Synchronized Reserve Event as determined in subsection (j) below;

G = the applicable Market Revenue Neutrality Offset as determined in subsection (f)(iii) above; and

H = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A(f)(iii) above if not eligible for Market Revenue Neutrality Offset.

(v) The opportunity costs for an Economic Load Response Participant resource assigned Synchronized Reserve in real-time or any resource self-scheduled for Synchronized Reserves shall be zero.

(g) [Reserved for future use]

(h) For each operating hour, the sum of the Synchronized Reserve lost opportunity cost credits credited in accordance with subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Synchronized Reserve Obligation in proportion to its real-time purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) [Reserved for future use]

(j) In the event a generation resource or Economic Load Response Participant resource that either has been assigned by the Office of the Interconnection or self-scheduled to provide Synchronized Reserve in real-time fails to provide the amount of Synchronized Reserve it was directed to deploy in response to a Synchronized Reserve Event, the resource will be charged at the Real-time Synchronized Reserve Market Clearing Price for the real-time Synchronized Reserve the resource was directed to deploy, in excess of the amount that actually responded for all Real-time Settlement Intervals the resource was assigned or self-scheduled Synchronized Reserve real-time. For each Real-time Settlement Interval where there is not a Synchronized Reserve Event, the megawatts that will be charged shall be the lesser of the amount of the shortfall of Synchronized Reserve, measured in megawatts, or the real-time Synchronized Reserve assignment, which is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements for the resource on the Operating Day during which the event occurred. The determination of the amount of Synchronized Reserve credited to a resource shall be on an individual resource basis, not on an aggregate basis.

The resource shall refund payments received for Synchronized Reserve it failed to provide. For purposes of determining the amount of the payments to be refunded by a Market Participant, the Office of the Interconnection shall calculate the shortfall of Synchronized Reserve on an individual resource basis unless the Market Participant had multiple resources that were assigned or self-scheduled to provide Synchronized Reserve, in which case the shortfall will be determined on an aggregate basis. For performance determined on an aggregate basis, the response of any resource that was assigned or self-scheduled for Synchronized Reserve and provided more Synchronized Reserve than it was directed to deploy will be used to offset the performance of other resources that provided less assigned or self-scheduled Synchronized Reserve than they were directed to deploy during a Synchronized Reserve Event, as calculated in the PJM Manuals. The determination of a Market Participant's aggregate response shall not be taken into consideration in the determination of the amount of Synchronized Reserve credited to each individual resource.

The amount refunded shall be determined by multiplying the retroactive penalty megawatts by the Real-time Synchronized Reserve Market Clearing Price for all intervals the resource was assigned or self-scheduled to provide Synchronized Reserve for a period of time immediately preceding the Synchronized Reserve Event equal to the lesser of the average number of days between Synchronized Reserve Events, or the number of days since the resource last failed to provide the amount of Synchronized Reserve it was directed to deploy in response to a Synchronized Reserve Event. The retroactive penalty megawatts for each interval shall be the lesser of the amount of the shortfall of Synchronized Reserve, measured in megawatts, and the real-time Synchronized Reserve assignment for each interval, which is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements for the resource. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the

results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following January 1. The refunded charges shall be allocated as credits to Market Participants based on its pro rata share of the Synchronized Reserve Obligation megawatts in the hour(s) of the Synchronized Reserve Event for the Reserve Sub-zone or Reserve Zone, except that Market Participants that incur a refund obligation and also have an applicable Synchronized Reserve Obligation during the hour(s) of the Synchronized Reserve Event shall not be included in the allocation of such refund credits. If the event spans multiple hours, the refund credits will be prorated hourly based on the duration of the event within each clock hour.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or an Economic Load Response Participant resource, except for Batch Load Economic Load Response Participant Resources covered by section 3.2.3A(l) below, is the difference between the generation resource's output or the Economic Load Response Participant resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Economic Load Response Participant resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Economic Load Response Participant resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or an Economic Load Response Participant resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Economic Load Response Participant resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to an Economic Load Response Participant resource will be reduced by the amount the megawatt consumption of the Economic Load Response Participant resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Economic Load Response Participant Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load Economic Load Response Participant Resource's consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Economic Load Response Participant Resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Economic Load Response Participant Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant's hourly Non-Synchronized Reserve Obligation shall be adjusted by any Non-Synchronized Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Non-Synchronized Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Non-Synchronized Reserve as defined in sections 3.2.3A.001(b)(i) and (ii) below.

(b) Resources assigned to provide Non-Synchronized Reserve at the direction of the Office of the Interconnection shall be credited as follows:

(i) Credits for Non-Synchronized Reserve provided by generation resources assigned to provide Non-Synchronized Reserve by the Office of the Interconnection in the Day-ahead Non-Synchronized Reserve Market shall be equal to the product of the Day-ahead Non-Synchronized Market Clearing Price multiplied by the megawatt amount of Non-Synchronized Reserve such resource is assigned to provide.

(ii) Credits for Non-Synchronized Reserve provided by generation resources assigned to provide Non-Synchronized Reserve by the Office of the Interconnection in the Real-time Non-Synchronized Reserve Market shall be determined for each operating hour based on the sum on their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$$\sum_i ((A - B) * C)$$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Non-Synchronized Reserve from that resource assigned by the Office of the Interconnection in the Real-time Non-Synchronized Reserve Market;

B = For each Real-time Settlement Interval, the megawatts of Non-Synchronized Reserve from that resource assigned by the Office of the Interconnection in the Day-ahead Non-Synchronized Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Non-Synchronized Reserve Market Clearing Price.

(iii) Pool-scheduled generation resources assigned to provide Non-Synchronized Reserve in the Day-ahead Non-Synchronized Reserve Market shall be credited a Non-Synchronized Reserve lost opportunity cost credit, where positive, as determined in accordance with subsection (d)(iii) below, to recover any net monetary loss to the Market Seller of such resource associated with the purchase of Non-Synchronized Reserve in the Real-time Non-Synchronized Reserve Market as a result of following the dispatch direction of the Office of the Interconnection.

(c) Non-Synchronized Reserve Market Clearing Prices

(i) For the Day-ahead Non-Synchronized Reserve Market, the Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Non-Synchronized Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for Primary Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Non-Synchronized Reserve offer prices and the Operating Reserve Demand Curve for Primary Reserve for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Primary Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute and (B) the price of serving the next increment of demand for 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.10.8(d), Day-ahead Non-Synchronized Reserve Market Clearing Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and Day-ahead Non-Synchronized Reserve Market Clearing Price of zero dollars per megawatt-hour and all settlements will be based on the Real-time Non-Synchronized Reserve market quantities and prices as determined pursuant to subsection (c)(ii) hereof.

(ii) For the Real-time Non-Synchronized Reserve Market, the Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for Primary Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Non-Synchronized Reserve offer prices and the Operating Reserve Demand Curve for Primary Reserve for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Primary Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute and (B) the price of serving the next increment of demand for 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, and the Office of the Interconnection is not assigning Non-Synchronized Reserves, then the Non-Synchronized Reserve Clearing Price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, where the real-time Market Suspension is less than or equal to six (6) consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Non-Synchronized Reserves, then the Non-Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Non-Synchronized Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than six (6) consecutive hours but less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating Days, and there are cleared Day-ahead Non-Synchronized Reserve Market Clearing Prices for the affected Operating Day, then the Real-time Non-Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the Day-ahead Non-Synchronized Reserve Market Clearing Prices for each corresponding hour. If no such Day-ahead Non-Synchronized Reserve Market Clearing Prices exist, then the Non-Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Non-Synchronized Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than twenty-four (24) consecutive hours, the Non-Synchronized Reserve Market Clearing Price will be set to zero dollars per megawatt-hour regardless of whether the Office of the Interconnection is assigning Non-Synchronized Reserves.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Non-Synchronized Reserve Market Clearing Price shall be the product of 1.5 multiplied by the Reserve Penalty Factor for the Primary Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

(iii) The Reserve Penalty Factor for the Minimum Primary Reserve Requirement shall be $2,000/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $2,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Reserve Penalty Factor

on the Operating Reserve Demand Curves for Primary Reserve are warranted for subsequent Delivery Year(s).

(d) (i) For determining the Non-Synchronized Reserve clearing price for each hour in the Day-ahead Non-Synchronized Reserve Market and for each Real-time Settlement Interval in the Real-time Non-Synchronized Reserve Market, including during a declaration of a Market Suspension, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves will be zero.

(ii) For each Real-time Settlement Interval, a total Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in real-time reserve MW from a day-ahead market assignment in more than one market for that Real-time Settlement Interval, the total Market Revenue Neutrality Offset is allocated to the Non-Synchronized Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Non-Synchronized Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Non-Synchronized Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Non-Synchronized Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Non-Synchronized Reserve assignment decreases due to the resource being self-scheduled to provide energy, Synchronized Reserve, or Regulation;

(B) A resource reduces flexibility in real-time such that the resource no longer qualifies to provide Non-Synchronized Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time; or

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above.

(iii) A Non-Synchronized Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

(zero) – (A + B + C + D)

Where:

A = day-ahead clearing price credits as determined in subsection (b)(i) above;

B = real-time clearing price credits as determined in subsection (b)(ii) above;

C = the applicable Market Revenue Neutrality Offset as determined in subsection (d)(ii) above; and

D = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A.001(d)(ii) above if not eligible for Market Revenue Neutrality Offset.

(e) [Reserved for future use]

(f) For each operating hour, the sum of the Non-Synchronized Reserve lost opportunity cost credits credited in subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation in proportion to its real-time purchases of Non-Synchronized Reserve in megawatt-hours during that hour.

(g) The magnitude of response to a Non-Synchronized Reserve Event by a generation resource is the difference between the generation resource's output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output at the start of the event is defined as the lowest telemetered generator resource output between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output 10 minutes after the start of the event is defined as the greatest generator resource output achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(h) In the event a generation resource that has been assigned by the Office of the Interconnection to provide Non-Synchronized Reserve fails to provide the assigned amount of Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the contiguous Real-time Settlement Interval the resource was assigned Non-Synchronized Reserve during which the event occurred.

3.2.3A.01 Secondary Reserve.

(a) Each Market Participant that is a Load Serving Entity shall have an obligation for hourly Secondary Reserve equal to its pro rata share of Secondary Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Secondary Reserve

Obligation"). A Market Participant's hourly Secondary Reserve Obligation shall be adjusted by any Secondary Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Secondary Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Secondary Reserve as defined in sections 3.2.3A.01(b)(i) and (ii) below.

(b) Resources assigned to provide Secondary Reserve at the direction of the Office of the Interconnection shall be credited as follows:

(i) Credits for Secondary Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Secondary Reserve by the Office of the Interconnection in the Day-ahead Secondary Reserve Market shall be equal to the product of the Day-ahead Secondary Reserve Market Clearing Price multiplied by the megawatt amount of Secondary Reserve such resource is scheduled to provide.

(ii) Credits for Secondary Reserve provided by generation resources and Economic Load Response Participant resources scheduled to provide Secondary Reserve by the Office of the Interconnection in the Real-time Secondary Reserve Market shall be determined for each operating hour based on the sum of their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$$\sum_i ((A - B) * C)$$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Secondary Reserve from that resource assigned by the Office of the Interconnection in the Real-time Secondary Reserve Market. The megawatt value is capped at the lesser of the Economic Maximum or Secondary Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval minus the Real-time Synchronized Reserve assignment;

B = For each Real-time Settlement Interval, the megawatts of Secondary Reserve from that resource scheduled by the Office of the Interconnection in the Day-ahead Secondary Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Secondary Reserve Market Clearing Price.

(iii) Pool-scheduled resources and Economic Load Response Participant resources shall be credited a Secondary Reserve lost opportunity cost credit, where positive, as described in subsection (f)(iv) below.

(c) [Reserved for future use]

(d) Secondary Reserve Market Clearing Prices

(i) For the Day-ahead Secondary Reserve Market, the Secondary Reserve Market Clearing Price shall be determined for each Reserve Zone and, as applicable, Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Secondary Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for 30-minute Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Secondary Reserve offer prices and opportunity costs and the Operating Reserve Demand Curve for 30-minute Reserve for that Reserve Zone or Reserve Sub-zone, plus the price of serving the next increment of demand for 30-minute Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.10.8(d), Day-ahead Secondary Reserve Market Clearing Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and Day-ahead Secondary Reserve Market Clearing Price of zero dollars per megawatt-hour and all settlements will be based on the Real-time Secondary Reserve market quantities and prices as determined pursuant to subsection (d)(ii) hereof.

(ii) For the Real-time Secondary Reserve Market, the Secondary Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for 30-minute Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Secondary Reserve offer prices and opportunity costs and the Operating Reserve Demand Curve for 30-minute Reserve for that Reserve Zone or Reserve Sub-zone plus the price of serving the next increment of demand for 30-minute Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, and the Office of the Interconnection is not assigning Secondary Reserves, then the Secondary Reserve Clearing Price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, where the real-time Market Suspension is less than or equal to six (6) consecutive hours, which may span up to two Operating Days, and the

Office of the Interconnection is assigning Secondary Reserves, then the Secondary Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Secondary Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than six (6) consecutive hours but less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating Days, and there are cleared Day-ahead Secondary Reserve Market Clearing Prices for the affected Operating Day, then the Real-time Secondary Reserve Market Clearing Prices associated with such Market Suspension shall be the Day-ahead Secondary Reserve Market Clearing Prices for each corresponding hour. If no such Day-ahead Secondary Reserve Market Clearing Prices exist, then the Secondary Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Secondary Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than twenty-four (24) consecutive hours, and the Office of the Interconnection is assigning Secondary Reserves, the Secondary Reserve Market Clearing Price will be set to zero dollars per megawatt-hour. Resources will be compensated for lost opportunity cost per subsection (f) hereof using the energy price as determined in Operating Agreement, Schedule 1, section 2.5.2.iii.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Secondary Reserve Market Clearing Price for a given Reserve Zone or Sub-zone shall be the Reserve Penalty Factor for the 30-minute Reserve Requirements for that Reserve Zone or Reserve Sub-zone.

(iii) The Reserve Penalty Factor for the Minimum 30-minute Reserve Requirement shall be $2000/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $2,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Reserve Penalty Factor on the Operating Reserve Demand Curves for 30-minute Reserve are warranted for subsequent Delivery Year(s).

(e) (i) For determining the Secondary Reserve Market Clearing Price for each hour in the Day-ahead Secondary Reserve Market, the estimated resource-specific opportunity cost for a generation resource or Economic Load Response Participant resources shall be the difference between the Locational Marginal Price at the generation or Economic Load Response Participant resource bus and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) or offer price to reduce energy from

the Economic Load Response Participant resource in the PJM Interchange Energy Market when the Locational Marginal Price at the Economic Load Response Participant resource bus is greater than the offer price for energy from the generation resource or the offer price to reduce energy from the Economic Load Response Participant resource.

However, opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve, and for synchronous condensers and for Economic Load Response Participant resources that do not receive a day-ahead commitment to provide energy in the same operating hour in which such resource is committed to provide Secondary Reserve.

(ii) For determining the Secondary Reserve Market Clearing Price for each Real-time Settlement Interval in the Real-time Secondary Reserve Market, the estimated unit-specific opportunity cost for a generation resource that is not a hydroelectric resource shall be the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

For hydroelectric resources, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

However, the opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve, and for synchronous condensers and Economic Load Response Participant resources.

(f) (i) In determining the credit under subsection (b) to a generation resource, except a generation resource that is a synchronous condenser, selected to provide Secondary Reserve in the Day-ahead Secondary Reserve Market or an Economic Load Response Participant resource that is selected to provide Secondary Reserve in the Day-ahead Secondary Reserve Market in the same operating hour in which such resource

receives a day-ahead commitment to provide energy, the opportunity cost of a resource shall be determined for each operating hour that the Office of the Interconnection requires a resource to provide Secondary Reserve and shall be in accordance with the following equation:

(A x B) – C

Where:

A = The Day-ahead Locational Marginal Price at the generation bus of the generation resource or the applicable pricing point for the Economic Load Response Participant resource;

B= The deviation of the resource's energy output or load reduction necessary to supply a Day-ahead Secondary Reserve assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load less any Day-ahead Synchronized Reserve Market assignment; and

C = The Day-ahead Energy Market offer integrated under the applicable energy offer curve for the resource's energy output or load reduction necessary to provide a Day-ahead Secondary Reserve Market assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load less any Day-ahead Synchronized Reserve Market assignment.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [Condense Energy Use multiplied by A] plus [the applicable Condense Startup Cost divided by the number of hours the resource is assigned Secondary Reserve].

(ii) In determining the credit under subsection (b) to a generation resource, except a generation that is a synchronous condenser, selected to provide Secondary Reserve in the Real-time Secondary Reserve Market in excess of the resource's Day-ahead Secondary Reserve Market assignment and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of that generation resource shall be determined for each Real-time Settlement Interval that the Office of the Interconnection requires that generation resource to provide Secondary Reserve and shall be in accordance with the following equation:

(A x B) – C

Where:

A = The Real-time Locational Marginal Price at the generation bus of the generation resource;

B= The deviation of the generation resource's output necessary to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment and follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy less any Real-time Synchronized Reserve Market assignment; and

C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Secondary Reserve in real-time from the lesser of the generation resource's output necessary to provide a Day-ahead Secondary Reserve Market assignment or follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy less any Real-time Synchronized Reserve Market assignment.

For hydroelectric resources, the unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the real-time Locational Marginal Price at that generation bus multiplied by the additional megawatts assigned to supply Synchronized Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average real-time Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating multiplied by the additional megawatts assigned to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: additional Condense Energy Use in excess of day-ahead Condense Energy Use multiplied by A plus [any applicable Condense Startup Cost due to additional Condense Startup Cost in real-time in excess of day-ahead Condense Startup Cost allocated to each Real-time Settlement Interval as described in PJM Manuals]. If the generation resource is operating as a synchronous condenser and also has a Real-time Synchronized Reserve assignment, resource's unit-specific opportunity cost in the Secondary Reserve Market shall be zero.

(iii) For each Real-time Settlement Interval, a total Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in real-time reserve MW from a day-ahead market assignment in more than one market for that real-time settlement interval, the total Market Revenue Neutrality Offset is allocated to the Secondary Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Secondary Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Secondary Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Secondary Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Secondary Reserve assignment decreases due to the resource being self-scheduled to provide energy, Synchronized Reserve, or Regulation;

(B) A resource reduces flexibility in real-time such that the resource no longer qualifies to provide Secondary Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time;

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above; or

(F) A resource that fails to come online and reach Economic Minimum output within 30 minutes as described in section 3.2.3A.01(h)(i) below.

(iv) A Secondary Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

(A + B) – (C + D + E + F)

Where:

A = day-ahead opportunity cost as determined in subsection (f)(i) above;

B = real-time opportunity cost as determined in subsection (f)(ii) above;

C = day-ahead clearing price credits as determined in subsection (b)(i) above;

D = real-time clearing price credits as determined subsection (b)(ii) above;

E = the applicable Market Revenue Neutrality Offset as determined in subsection (f)(iii) above; and

F = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A.01(f)(iii) above if not eligible for Market Revenue Neutrality Offset.

(v) The opportunity costs for Economic Load Response Participant resources and generation resources not synchronized to the grid shall be zero, except that Economic Load Response Participant resources may have a day-ahead opportunity cost, as determined in subsection (f)(i) above.

(g) For each operating hour, the sum of the Secondary Reserve lost opportunity cost credits credited in accordance with subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Secondary Reserve Obligation in proportion to its real-time purchases of Secondary Reserve in megawatt-hours during that hour.

(h) (i) In the event an offline generation resource has been assigned by the Office of the Interconnection to provide Secondary Reserve in real-time and is subsequently dispatched by the Office of the Interconnection to supply energy during that Operating Day and the resource qualifies as a Secondary Reserve resource at the time it is dispatched to provide energy, the Office of the Interconnection will assess the resource's performance as follows:

For each generation resource that fails to come online and reach Economic Minimum output within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval and for all prior intervals in which the resource was assigned to provide Secondary Reserve in the Real-time Secondary Reserve Market starting at the later of (A) the last interval the resource was online or (B) the beginning of that Operating Day and continuing up to the interval the resource failed to come online. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time not being paid for the assigned MW.

(ii) In the event an Economic Load Response Participant resource has been assigned by the Office of the Interconnection to provide Secondary Reserve in real-time and is subsequently dispatched to supply the Secondary Reserve assignment as a load reduction, the Office of the Interconnection will assess the resource's performance as follows:

For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between 29 and 31 minutes after the issuance of a dispatch instruction from the Office of the Interconnection.

For each Economic Load Response Participant resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described above, within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval, and for all prior intervals in which the resource was assigned to provide Secondary Reserve in the Real-time Secondary Reserve Market between such non-performance event starting at the later of (A) the last interval the resource reduced load at the instruction of the Office of the Interconnection or (B) the beginning of that Operating Day, and for all subsequent intervals through the earlier of (C) the next interval in which the resource is dispatched to reduce load or (D) the end of the Operating Day. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time, refunding all payments due for Secondary Reserve during such period.

(iii) For Batch Load Economic Load Response Participant Resources, a second method of verification will be used for instances where a Secondary Reserve assignment dispatched as an energy load reduction is initiated and the resource is operating at the minimum consumption level of its duty cycle. In this case, the magnitude of the response will be measured as the difference between (A) the minimum of the resource's consumption between the minute before and the minute after the end of the last settlement interval the resource reduced load at the instruction of the Office of the Interconnection and (B) the maximum consumption within a ten (10) minute period following the end of the last settlement interval the resource reduced load provided that all subsequent minutes following that minute are no less than 50% of the consumption in that minute.

For each Batch Load Economic Load Response Participant Resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described in section (ii) above or the difference between (A) and (B) as described in section (iii) above, within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval, and for all prior intervals in which the resource was assigned to provide Secondary Reserve in either the Day-ahead or Real-time Secondary Reserve Markets between such non-performance event starting at the later of (A) the last interval the resource reduced load at the instruction of the Office of the Interconnection or (B) the beginning of that Operating Day, and for all subsequent intervals through the earlier of (C) the next interval in which the resource is dispatched to reduce load or (D) the end of the Operating Day. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time, refunding all payments due for Secondary Reserve during such period.

3.2.3A.02 Operating Reserve Demand Curves

(a) Operating Reserve Demand Curves

The Office of the Interconnection shall establish Operating Reserve Demand Curves for clearing 30-minute Reserve, Primary Reserve, and Synchronized Reserve, for, as applicable, each Reserve Zone or Reserve Sub-zone to procure sufficient reserves to meet reliability requirements in light of supply and demand uncertainties. The Operating Reserve Demand Curves established for each reserve type shall be used to commit such reserves in both the day-ahead and real-time reserve markets. The Operating Reserve Demand Curves shall be determined in accordance with subsection (b) and the PJM Manuals.

(b) Methodology for Establishing Operating Reserve Demand Curves

For each three-month season, Winter (December through February), Spring (March through May), Summer (June through August), and Fall (September through November), and for each time-of-day block set forth in the PJM Manuals, the Office of the Interconnection shall establish Operating Reserve Demand Curves for each Reserve Zone or Reserve Sub-zone as follows:

(i) Each Operating Reserve Demand Curve shall be plotted on a graph on which megawatts of reserve is on the x-axis and price is on the y-axis;

(ii) The Operating Reserve Demand Curve for each Reserve Zone or Reserve Sub-zone shall be plotted by combining (i) a straight horizontal line starting from point (1) on the y-axis to point (2), (ii) a straight vertical line connecting points (2) and (3), and (iv) a curved line from point (3) to the x-axis, where:

(A) Point (1) is the point on the y-axis(price) equal to the Reserve Penalty Factor for the minimum reserve requirement for the subject reserve requirement (i.e., the Minimum 30-minute Reserve Requirement, the Minimum Primary Reserve Requirement, or the Minimum Synchronized Reserve Requirement);

(B) Point (2) has the y-axis coordinate of point (1) and the x-axis coordinate of the applicable minimum reserve requirement as determined for the Reserve Zone or Reserve Sub-zone in accordance with the PJM Manuals;

(C) Point (3) has the x-axis coordinate of the applicable minimum reserve requirement and the y-axis coordinate resulting from multiplying the Reserve Penalty Factor of the applicable minimum reserve requirement by the probability of falling below the applicable minimum reserve requirement when procuring an infinitesimal amount of additional MW of reserves beyond the minimum reserve requirement; and

(D) From point (3) to the x-axis, first, the Office of the Interconnection develops a curve starting at point (3). The shape of the curve will be determined by multiplying the Reserve Penalty Factor of the applicable minimum reserve requirement by the probability of falling below the applicable minimum reserve requirement when procuring each additional MW of reserves beyond the minimum reserve requirement until the resulting product falls below $0.01/MWh at which point the curve will intersect with the x-axis. These probabilities are calculated from an empirical distribution of data from a rolling three-calendar

year period of the following supply and demand uncertainties, using a 30-minute time horizon for clearing Primary Reserves and Synchronized Reserves and a 60-minute time horizon for clearing 30-minute Reserves: load forecast error, wind forecast error, solar forecast error, and forced outages of thermal units, and, for the Operating Reserve Demand Curves for 30-minute Reserves only, net interchange forecast error, all as described in the PJM Manuals. The empirical distribution also accounts for the Regulation requirement, expressed in effective megawatts, that PJM has established for each hour within that time-of-day block, by reducing the magnitude of the above uncertainties by the requirement.

The Office of the Interconnection will post each Operating Reserve Demand Curve used to clear reserve markets.

(c) Annual Update of Operating Reserve Demand Curves

On an annual basis, the Office of the Interconnection shall update the determination of the probability of falling below the applicable minimum reserve requirement, including each uncertainty, to account for the most recent calendar year's data, in accordance with the PJM Manuals, and post revised Operating Reserve Demand Curves by April 1. The revised Operating Reserve Demand Curves shall become effective June 1, coincident with the start of the next Delivery Year.

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output, when positive, of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from a steam-electric generating unit, an Energy Storage Resource Model Participant, a Hybrid Resource, or a combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Tariff, Attachment K-Appendix, section 1.10.3(c) hereof), and where the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the

generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C. An Energy Storage Resource Model Participant or a Hybrid Resource instructed to reduce charging to provide Reactive Services is not eligible for compensation under section (c).

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Tariff, Attachment K-Appendix, section 1.10.3(c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost for each Real-time Settlement Interval, limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(e) At the end of each Operating Day, where the active energy output (positive generation output) of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to section 3.2.3B(f). At the end of each Operating Day, when an Energy Storage Resource Model Participant or a Hybrid Resource is instructed to increase charging at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from a steam-electric generating unit, an Energy Storage Resource Model Participant, a Hybrid Resource, a combined cycle unit, or a combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Tariff, Attachment K-Appendix, section 1.10.3(c) hereof), and where the real time LMP revenues at the unit's bus are lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit in an amount equal to {(AG – TRLD MWh) x (UB - URTLMP)}where:

AG equals the actual output of the unit;

TRLD MWh equals the Tracking Ramp Limited Desired MWh determined according to Tariff, Attachment K-Appendix, section 3.2.3(e-1);

UB equals the unit offer for that unit for which output, or charging, is increased, determined according to the lesser of the Final Offer or Committed Offer;

URTLMP equals the real time LMP at the unit's bus; and

where UB - URTLMP shall not be negative, except where applicable for an Energy Storage Resource Model Participant or a Hybrid Resource when instructed to increase charging.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Tariff, Attachment K-Appendix, section 1.10.3(c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability or if an Energy Storage Resource Model Participant or a Hybrid Resource believes the above calculations in this section 3.2.3B do not accurately compensate the Market Participant for opportunity costs associated with following the Office of the Interconnection's dispatch instructions to modify a unit's charging or discharging for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate opportunity cost compensation, the Office of the Interconnection shall invoice the Market Participant accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in section 3.2.3A regarding provision of Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Synchronized Reserve Market Clearing Price for each Real-time Settlement Interval a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the product of the Condense Energy Use multiplied by the real time LMP at the generating unit's bus, (B) the generating unit's Condense Startup Cost, and (C) the unit-specific lost opportunity cost of the generating resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM

Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generating unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of the Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees in accordance with section 3.2.3(e-2). The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load ((a) net of operating Behind The Meter Generation; and (b) excluding Direct Charging Energy) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the applicable Synchronized Reserve Requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in section 3.2.3A regarding provision of 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Real-time Synchronized Reserve Market Clearing Price for each applicable interval a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the product of the Condense Energy Use multiplied by the real-time LMP at the generation bus of the generation resource, (B) the generation resource's Condense Startup Cost, and (C) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on

whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load ((a) net of operating Behind The Meter Generation; and (b) excluding Direct Charging Energy) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

Each Market Buyer shall be assessed Transmission Congestion Charges as specified in Tariff, Attachment K-Appendix, section 5.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Tariff, Attachment K-Appendix, section 5.

3.2.6 Emergency Energy.

(a) When the Office of the Interconnection has implemented Emergency procedures, resources offering Emergency energy are eligible to set real-time Locational Marginal Prices, capped at the energy offer cap plus sum of the applicable Reserve Penalty Factors for the Synchronized Reserved Requirement and Primary Reserve Requirement, provided that the Emergency energy is needed to meet demand in the PJM Region.

(b) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each applicable interval of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(c) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each applicable interval of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(d) The net costs or net revenues associated with sales or purchases of energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each applicable interval of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Participant in accordance with the charges and credits specified in sections 3.2.1 through 3.2.6, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Participant's internal accounting.

(b) If deliveries to a Market Participant that has PJM Interchange meters in accordance with Operating Agreement, section 14 include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market Participant, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market Participant and the unmetered Market Participant specified by them to the Office of the Interconnection.

3.3A Economic Load Response Participants.

3.3A.1 Compensation.

Economic Load Response Participants shall be compensated pursuant to sections 3.3A.5 and/or 3.3A.6 of this Schedule, for demand reduction offers submitted in the Day-Ahead Energy Market or Real-time Energy Market that satisfy the Net Benefits Test of section 3.3A.4; that are scheduled by the Office of the Interconnection; and that follow the dispatch instructions of the Office of the Interconnection. Qualifying demand reductions shall be measured by: 1) comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of section 3.3A.2 or 3.3A.2.01, respectively; or 2) non-interval metered residential Direct Load Control customers, as metered on a current statistical sample of electric distribution company accounts, as described in the PJM Manuals or 3) by the MWs produced by on-Site Generators pursuant to the provisions of section 3.3A.2.02.

3.3A.2 Customer Baseline Load.

For Economic Load Response Participants that choose to measure demand reductions using an end-use customer's Customer Baseline Load ("CBL"), the CBL shall be determined using the following formula for such participant's Non-Variable Loads. Additionally, the following formula shall be used to determine a Peak Shaving Adjustment end-use customer's demand reductions when determining peak shaving performance rating as described in PJM Manual 19, unless an alternative CBL is approved pursuant to section 3.3A.2.01 of this schedule:

(a) The CBL for weekdays shall be the average of the highest 4 out of the 5 most recent load weekdays in the 45 calendar day period preceding the relevant load reduction event.

i. For the purposes of calculating the CBL for weekdays, weekdays shall not include:

1. NERC holidays;

2. Weekend days;

3. Event days. For the purposes of this section an event day shall be either:

(i) any weekday that an Economic Load Response Participant submits a settlement pursuant to section 3.3A.4 or 3.3A.5, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection; or

(ii) any weekday where the end-use customer location that is registered in the Economic Load Response program is also registered as a Demand Resource, and all end-use customer

locations on the relevant Economic Load Response registration have been dispatched by PJM during an emergency event.

4. Any weekday where the average daily event period usage is less than 25% of the average event period usage for the five days.

ii. If a 45-day period does not include 5 weekdays that meet the conditions in subsection (a)(i) of this section, provided there are 4 weekdays that meet the conditions in subsection (a)(i) of this section, the CBL shall be based on the average of those 4 weekdays. If there are not 4 eligible weekdays, the CBL shall be determined in accordance with subsection (iii) of this section.

iii. Section 3.3A.2(a)(i)(3) notwithstanding, if a 45-day period does not include 4 weekdays that meet the conditions in subsection (a)(i) of this section, event days will be used as necessary to meet the 4 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(b) The CBL for weekend days and NERC holidays shall be determined in accordance with the following provisions:

i. The CBL for Saturdays and Sundays/NERC holidays shall be the average of the highest 2 load days out of the 3 most recent Saturdays or Sundays/NERC holidays, respectively, in the 45 calendar day period preceding the relevant load reduction event, provided that the following days shall not be used to calculate a Saturday or Sunday/NERC holiday CBL:

1. Event days. For the purposes of this section an event day shall be either:

a. any Saturday and Sunday/NERC holiday that an Economic Load Response Participant submits a settlement pursuant to section 3.3A.5 or 3.3A.6, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection; or

b. any Saturday and Sunday/NERC holiday where the end-use customer that is registered in the Economic Load Response program is also registered as a Demand Resource, and all end-use customer locations on the relevant Economic Load Response registration have been dispatched by PJM during an emergency event.

2. Any Saturday or Sunday/NERC holiday where the average daily event period usage is less than 25% of the average event period usage level for the three days;

3. Any Saturday or Sunday/NERC holiday that corresponds to the beginning or end of daylight savings.

ii. If a 45-day period does not include 3 Saturdays or 3 Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, provided there are 2 Saturdays or Sundays/NERC holidays that meet the conditions in subsection (b)(i) of this section, the CBL will be based on the average of those 2 Saturdays or Sundays/NERC holidays. If there are not 2 eligible Saturdays or Sundays/NERC holidays, the CBL shall be determined in accordance with subsection (iii) of this section.

iii. Section 3.3A.2(b)(i)(1) notwithstanding, if a 45-day period does not include 2 Saturdays or Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, event days will be used as necessary to meet the 2 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(c) CBLs established pursuant to this section shall represent end-use customers' actual load patterns. If the Office of the Interconnection determines that a CBL or alternative CBL does not accurately represent a customer's actual load patterns, the CBL shall be revised accordingly pursuant to section 3.3A.2.01. Consistent with this requirement, if an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer upon whose behalf it is acting that would result in the adjustment of more than half the hours in the affected party's Customer Baseline Load by twenty percent or more for more than twenty days.

3.3A.2.01 Alternative Customer Baseline Methodologies.

(a) During the Economic Load Response Participant registration process pursuant to section 1.5A.3 of this Schedule, the relevant Economic Load Response Participant or the Office of the Interconnection ("Interested Parties") may, in the case of such participant's Non-Variable Load customers, and shall, in the case of its Variable Load customers, propose an alternative CBL calculation that more accurately reflects the relevant end-use customer's consumption pattern relative to the CBL determined pursuant to section 3.3A.2. During the Emergency and Pre-Emergency Load Response registration process pursuant to section 8.4 of this schedule, or as otherwise approved by the Office of the Interconnection, the relevant participant or the Office of the Interconnection may propose an alternative CBL calculation that more accurately reflects the relevant end-use customer's consumption pattern relative to the CBL determined pursuant to section 3.3A.2 of this schedule. In support of such proposal, the participant shall demonstrate that the alternative CBL method shall result in an hourly relative root mean square error of twenty percent or less compared to actual hourly values, as calculated in accordance with the technique specified in the PJM Manuals. Any proposal made pursuant to this section shall be provided to the other Interested Party.

(b) The Interested Parties shall have 30 days to agree on a proposal issued pursuant to subsection (a) of this section. The 30-day period shall start the day the proposal is provided to

the other Interested Party. If both Interested Parties agree on a proposal issued pursuant to this section, that alternative CBL calculation methodology shall be effective consistent with the date of the relevant Economic Load Response Participant registration.

(c) If agreement is not reached pursuant to subsection (b) of this section, the Office of the Interconnection shall determine a CBL methodology that shall result, as nearly as practicable, in an hourly relative root mean square error of twenty percent or less compared to actual hourly values within 20 days from the expiration of the 30-day period established by subsection (b). A CBL established by the Office of the Interconnection pursuant to this subsection (c) shall be binding upon both Interested Parties unless the Interested Parties reach agreement on an alternative CBL methodology prior to the expiration of the 20-day period established by this subsection (c).

(d) Operation of this section 3.3A.2.01 shall not delay Economic Load Response Participant registrations pursuant to Section 1.5A.3, provided that the alternative CBL established pursuant to this section shall be used for all related energy settlements made pursuant to sections 3.3A.5 and 3.3A.6.

(e) The Office of the Interconnection shall periodically publish alternative CBL methodologies established pursuant to this section in the PJM Manuals.

(f) Emergency and Pre-Emergency Load Response registrations will use the CBL defined on the associated economic registration for measuring demand reductions when determining the participant's compliance with its capacity obligations pursuant to Schedule 6 of the RAA, unless it is the maximum baseload CBL as defined in the PJM Manuals, in which case the participant will use the CBL set forth in the Emergency or Pre-Emergency Load Response registration.

3.3A.2.02 On-Site Generators.

On-Site Generators used as the basis for Economic Load Response Participant status pursuant to Tariff, Attachment K-Appendix, section 1.5A shall be subject to the following provisions:

i. The On-Site Generator shall be used solely to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market and shall not otherwise have been operating;

ii. If subsection (i) does not apply, the amount of energy from an On-Site Generator used to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market shall be capable of being quantified in a manner that is acceptable to the Office of the Interconnection.

3.3A.3 Symmetric Additive Adjustment.

(a) Customer Baseline Levels established pursuant to section 3.3A.2 shall be adjusted by the Symmetric Additive Adjustment. Unless an alternative formula is approved by the Office of the Interconnection, the Symmetric Additive Adjustment shall be calculated using the following formula:

Step 1: Calculate the average usage over the 3 hour period ending 1 hour prior to the start of event.

Step 2: Calculate the average usage over the 3 hour period in the CBL that corresponds to the 3 hour period described in Step 1.

Step 3: Subtract the results of Step 2 from the results of Step 1 to determine the symmetric additive adjustment (this may be positive or negative).

Step 4: Add the symmetric additive adjustment (i.e. the results of Step 3) to each hour in the CBL that corresponds to each event hour.

(b) Following a Load Reduction Event that is submitted to the Office of the Interconnection for compensation, the Office of the Interconnection shall provide the Notification window(s), if applicable, directly metered data and Customer Baseline Load and Symmetric Additive Adjustment calculation to the appropriate electric distribution company for optional review. The electric distribution company will have ten Business Days to provide the Office of the Interconnection with notification of any issues related to the metered data or calculations.

3.3A.4 Net Benefits Test.

The Office of the Interconnection shall identify each month the price on a supply curve, representative of conditions expected for that month, at which the benefit of load reductions provided by Economic Load Response Participants exceed the costs of those reductions to other loads. In formulaic terms, the net benefit is deemed to be realized at the price point on the supply curve where (Delta LMP x MWh consumed) > (LMP_{NEW} x DR), where LMP_{NEW} is the market clearing price after Economic Load Response is dispatched and Delta LMP is the price before Economic Load Response is dispatched minus the LMP_{NEW}).

The Office of the Interconnection shall update and post the Net Benefits Test results and analysis for a calendar month no later than the 15th day of the preceding calendar month. As more fully specified in the PJM Manuals, the Office of the Interconnection shall calculate the net benefit price level in accordance with the following steps:

Step 1. Retrieve generation offers from the same calendar month (of the prior calendar year) for which the calculation is being performed, employing market-based price offers to the extent available, and cost-based offers to the extent market-based price offers are not available. To the extent that generation offers are unavailable from historical data due to the addition of a Zone to the PJM Region the Office of the Interconnection shall use the most recent generation offers that

best correspond to the characteristics of the calendar month for which the calculation is being performed, provided that at least 30 days of such data is available. If less than 30 days of data is available for a resource or group of resources, such resource[s] shall not be considered in the Net Benefits Test calculation.

Step 2: Adjust a portion of each prior-year offer representing the typical share of fuel costs in energy offers in the PJM Region, as specified in the PJM Manuals, for changes in fuel prices based on the ratio of the reference month spot price to the study month forward price. For such purpose, natural gas shall be priced at the Henry Hub price, number 2 fuel oil shall be priced at the New York Harbor price, and coal shall be priced as a blend of coal prices representative of the types of coal typically utilized in the PJM Region.

Step 3. Combine the offers to create daily supply curves for each day in the period.

Step 4. Average the daily curves for each day in the month to form an average supply curve for the study month.

Step 5. Use a non-linear least squares estimation technique to determine an equation that reasonably approximates and smooths the average supply curve.

Step 6. Determine the net benefit level as the point at which the price elasticity of supply is equal to 1 for the estimated supply curve equation established in Step 5.

3.3A.5 Market Settlements in Real-time Energy Market.

(a) Economic Load Response Participants that submit offers for load reductions in the Day-ahead Energy Market by no later than 2:15 p.m. on the day prior to the Operating Day that cleared or that otherwise are dispatched by the Office of the Interconnection for the Operating Day shall be compensated for reducing demand based on the actual kWh relief provided in excess of committed day-ahead load reductions. The offer shall contain the Offer Data specified in Tariff, Attachment K-Appendix, section 1.10.1A(k) and shall not thereafter be subject to change; provided, however, the Economic Load Response Participant may update the previously specified minimum or maximum load reduction quantity and associated price by submitting a Real-time Offer for a clock hour by providing notice to the Office of the Interconnection in the form and manner specified in the PJM Manuals no later than 65 minutes prior to such clock hour. Economic Load Response Participants may also submit Real-time Offers for a clock hour for an Operating Day containing Offer Data specified in Tariff, Attachment K-Appendix, section 1.10.1A(k), and may update such offers up to 65 minutes prior to such clock hour. Economic Load Response Participants may, at their option, combine separately registered loads that have a common pricing point into a single portfolio for purposes of offering and dispatching their load reduction capability; provided however that any load reductions will continue to be measured and verified at the individual registration level prior to aggregation at the portfolio level for purposes of energy market and balancing energy uplift settlements. An Economic Load Response Participant that curtails or causes the curtailment of demand in real-time in response to PJM dispatch, and for which the applicable real-time LMP is

equal to or greater than the threshold price established under the Net Benefits Test, will be compensated by PJMSettlement at the real-time Locational Marginal Price.

(b) In cases where the demand reduction follows dispatch, as defined in Tariff, Attachment K-Appendix, section 3.2.3(o-1), as instructed by the Office of the Interconnection, and the demand reduction offer price is equal to or greater than the threshold price established under the Net Benefits Test, payment will not be less than the total value of the demand reduction bid. For the purposes of this subsection, the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing demand, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the demand reduction must be committed.

Any shortfall between the applicable Locational Marginal Price and the total value of the demand reduction bid will be made up through normal, balancing Energy Make Whole credits. In all cases under this subsection, the applicable zonal or aggregate (including nodal) Locational Marginal Price shall be used as appropriate for the individual end-use customer. The foregoing notwithstanding, when calculating balancing Energy Make Whole credits for Economic Load Response Participants pursuant to Tariff, Attachment K-Appendix, section 3.2.3, the second Segment shall exclude shutdown costs.

(c) For purposes of load reductions qualifying for compensation hereunder, an Economic Load Response Participant shall accumulate credits for energy reductions in those hours when the energy delivered to the end-use customer is less than the end-use customer's Customer Baseline Load at the applicable Locational Marginal Price for the Real-time Settlement Interval. In the event that the end-use customer's hourly energy consumption is greater than the Customer Baseline Load, the Economic Load Response Participant will accumulate debits at the applicable Locational Marginal Price for the Real-time Settlement Interval for the amount the end-use customer's hourly energy consumption is greater than the Customer Baseline Load. If the actual load reduction, compared to the desired load reduction is outside the deviation levels specified in Tariff, Attachment K-Appendix, section 3.2.3(o-1), the Economic Load Response Participant shall be assessed balancing uplift charges equal to the Economic Load Response Participant's daily total of hourly deviations in each region times the regional adder rate for deviations in the relevant region plus the daily total of hourly deviations in the RTO region times the RTO region balancing uplift rate for deviations in accordance with Tariff, Attachment K-Appendix, section 3.2.3. The rates used for Economic Load Response Participant's balancing uplift charges are calculated in accordance with Tariff, Attachment K-Appendix, section 3.2.3(q-1), however the credits used in the calculation of the rates exclude balancing Energy Make Whole credits paid to Economic Load Response Participants. Market Participants with deviations in the RTO region, excluding Economic Load Response Participant deviations, shall be allocated any uplift credit associated with the collection of these charges.

(d) The cost of payments to Economic Load Response Participants under this section (excluding any portion of the payments recovered as balancing Energy Make Whole credits pursuant to subsection (b) of this section) for load reductions that are compensated at the applicable full LMP, in any Zone for any hour, shall be recovered from Market Participants on a ratio-share basis based on their real-time exports from the PJM Region and from Load Serving

Entities on a ratio-share basis based on their real-time loads in each Zone for which the load-weighted average Locational Marginal Price for the hour during which such load reduction occurred is greater than or equal to the price determined under the Net Benefits Test for that month, with the ratio shares determined as follows:

The ratio share for LSE **i** in zone **z** shall be $\mathbf{RTL_{iz}/(RTL + X)}$
and the ratio share for party **j** shall be $\mathbf{X_j/(RTL + X)}$.

Where:

RTL is the total real time load in all zones where LMP ≥ Net Benefits Test price;
$\mathbf{RTL_{iz}}$ is the real-time load for LSE **i** in zone **z**;
X is the total export quantity from PJM in that hour; and
$\mathbf{X_j}$ is the export quantity by party **j** from PJM.

3.3A.6 Market Settlements in the Day-ahead Energy Market.

(a) Economic Load Response Participants dispatched as a result of a qualifying demand reduction offer in the Day-ahead Energy Market shall be compensated for reducing demand based on the reductions of kWh committed in the Day-ahead Energy Market. An Economic Load Response Participant that submits a demand reduction bid day ahead that is accepted by the Office of the Interconnection and for which the applicable day ahead LMP is greater than or equal to the Net Benefits Test shall be compensated by PJMSettlement at the day-ahead Locational Marginal Price.

Economic Load Response Participants may, at their option, combine separately registered loads that have a common pricing point into a single portfolio for purposes of offering and dispatching their load reduction capability; provided however that any load reductions will continue to be measured and verified at the individual registration level prior to aggregation at the portfolio level for purposes of energy market and balancing uplift settlements.

(b) Total payments to Economic Load Response Participants for accepted day-ahead demand reduction bids with an offer price equal to or greater than the threshold price established under the Net Benefits Test that follow the dispatch instructions of the Office of the Interconnection will not be less than the total value of the demand reduction bid. For the purposes of this subsection, the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing load, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the load reduction must be committed. Any shortfall between the applicable Locational Marginal Price and the total value of the demand reduction bid will be made up through normal, day-ahead Energy Make Whole credits. In all cases under this subsection, the applicable zonal or aggregate (including nodal) Locational Marginal Price shall be used as appropriate for the individual end-use customer.

(c) Economic Load Response Participants that have demand reductions committed in the Day-ahead Energy Market that deviate from the day-ahead schedule in real time shall be

charged or credited for such variance at the real time LMP plus or minus an amount equal to the applicable balancing uplift charge in accordance with Tariff, Attachment K-Appendix, section 3.2.3. Load Serving Entities that otherwise would have load that was reduced shall receive any associated uplift credit.

(d) The cost of payments to Economic Load Response Participants for accepted day-ahead demand reduction bids that are compensated at the applicable full, day ahead LMP under this section (excluding any portion of the payments recovered as day-ahead Energy Make Whole credits pursuant to subsection (b) of this section) for load reductions in any Zone for any hour shall be recovered from Market Participants on a ratio-share basis based on their real-time exports from the PJM Region and from Load Serving Entities on a ratio-share basis based on their real-time loads in each Zone for which the load-weighted average real-time Locational Marginal Price for the hour during which such load reduction occurred is greater than or equal to the price determined under the Net Benefits Test for that month, in accordance with the formula prescribed in Tariff, Attachment K-Appendix, section 3.3A.5(d).

3.3A.7 Prohibited Economic Load Response Participant Market Settlements.

(a) Settlements pursuant to sections 3.3A.5 and 3.3A.6 shall be limited to demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market that satisfy the Net Benefits Test and are dispatched by the Office of the Interconnection.

(b) Demand reductions that do not meet the requirements of section 3.3A.7(a) shall not be eligible for settlement pursuant to sections 3.3A.5 and 3.3A.6. Examples of settlements prohibited pursuant to this section 3.3A.7(b) include, but are not limited to, the following:

i. Settlements based on variable demand where the timing of the demand reduction supporting the settlement did not change in direct response to Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market;

ii. Consecutive daily settlements that are the result of a change in normal demand patterns that are submitted to maintain a CBL that no longer reflects the relevant end-use customer's demand;

iii. Settlements based on on-site generation data if the On-Site Generator is not supporting demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market;

iv. Settlements based on demand reductions that are the result of operational changes between multiple end-use customer sites in the PJM footprint;

v. Settlements that do not include all hours that the Office of the Interconnection dispatched the load reduction, or for which the load reduction cleared in the Day-ahead Market.

(c) The Office of the Interconnection shall disallow settlements for demand reductions that do not meet the requirements of section 3.3A.7(a). If the Economic Load Response Participant continues to submit settlements for demand reductions that do not meet the requirements of section 3.3A.7(a), then the Office of the Interconnection shall suspend the Economic Load Response Participant's PJM Interchange Energy Market activity and refer the matter to the FERC Office of Enforcement.

3.3A.8 Economic Load Response Participant Review Process.

(a) The Office of the Interconnection shall review the participation of an Economic Load Response Participant in the PJM Interchange Energy Market under the following circumstances:

i. An Economic Load Response Participant's registrations submitted pursuant to Tariff, Attachment K-Appendix, section 1.5A.3 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).

ii. An Economic Load Response Participant's settlements pursuant to sections 3.3A.5 and 3.3A.6 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).

iii. An Economic Load Response Participant's settlements pursuant to sections 3.3A.5 and 3.3A.6 are denied by the Office of the Interconnection more than 10% of the time.

iv. An Economic Load Response Participant's registration will be reviewed when settlements are frequently submitted or if its actual loads frequently deviate from the previously scheduled quantities (as determined for purposes of assessing balancing uplift charges). PJM will notify the Participant when their registration is under review. While the Participant's registration is under review by PJM, the Participant may continue economic load reductions but all settlements will be denied by PJM until the registration review is resolved pursuant to subsection (i) or (ii) below. PJM will require the Participant to provide information within 30 days to support that the settlements were submitted for load reduction activity done in response to price and not submitted based on the end-use customer's normal operations.

i) If the Participant is unable to provide adequate supporting information to substantiate the load reductions submitted for settlement, PJM will terminate the registration and may refer the Participant to either the Market Monitoring Unit or the Federal Energy Regulatory Commission for further investigation.

ii) If the Participant does provide adequate supporting information, the settlements denied by PJM will be resubmitted by the Participant for review according to existing PJM market rules. Further, PJM may introduce an alternative Customer Baseline Load if the existing Customer

Baseline Load does not adequately reflect what the customer load would have been absent a load reduction.

v. The electric distribution company may only deny settlements during the normal settlement review process for inaccurate data including, but not limited to: meter data, line loss factor, Customer Baseline Load calculation, interval meter owner and a known recurring end-use customer outage or holiday.

(b) The Office of the Interconnection shall have thirty days to conduct a review pursuant to this section 3.3A.8. The Office of the Interconnection may refer the matter to the PJM MMU and/or the FERC Office of Enforcement if the review indicates the relevant Economic Load Response Participant and/or relevant electric distribution company or LSE is engaging in activity that is inconsistent with the PJM Interchange Energy Market rules governing Economic Load Response Participants.

8.8 Market Settlements

Payment for reducing load is based on the actual kWh relief provided plus the adjustment for losses, subject to the Reporting and Compliance provisions below. The magnitude of capacity relief provided by Full Program Option participants shall be the amount determined in accordance with the Reporting and Compliance provisions below. The magnitude of relief provided by Energy Only Option participants, and the magnitude of energy relief provided by Full Program Option participants, may be less than, equal to, or greater than the kW amount declared on the Emergency or Pre-Emergency registration. Compensation will be provided for reductions in energy consumption during emergency events, tests and associated retest(s), where applicable by Full Program Option participants and Energy Only Option participants regardless of whether the participant's load during the event exceeds its peak load contribution for the applicable Delivery Year.

PJMSettlement pays the applicable LMP to the PJM Member that nominates the load. Payment will be equal to the measured energy load reduction adjusted for losses times the applicable LMP. The measured energy load reduction for locations with approved Economic Load Response registrations prior to a Load Management Event that have an economic CBL different than the maximum base load as defined in the PJM Manuals will use the associated economic CBL to determine the energy load reduction unless the locations on the Emergency Load Response registration are not the same locations as those included on the Economic Load Response registration. If, at the time that a Load Management Event or emergency event is initiated by PJM, an end-use customer is already responding economically (i.e., pursuant to the Economic Load Response rules) and economic CBL is based on Symmetric Additive Adjustment, then the CBL calculated based on the Symmetric Additive Adjustment period prior to the economic event will be used. Locations that do not have an approved Economic Load Response registration prior to a Load Management Event will use the Customer Baseline Load as defined in section 3.3A.2 and associated Symmetric Additive Adjustment as defined in section 3.3A.2.01 of this schedule unless an alternative CBL is approved pursuant to section 3.3A.2.01 of this schedule as the CBL to determine the energy load reduction.

If, however, the sum of the hourly energy payments to a Curtailment Service Provider with a Demand Resource Registration dispatched by PJM for actual, achieved reductions for an emergency event is not greater than or equal to the offer value (i.e. Minimum Dispatch Price and shut down costs) then the Curtailment Service Provider will be made whole up to the offer value for its actual, achieved reductions for the Demand Resource Registration.

Locations on Economic Load Response registrations dispatched in the Real-time Energy Market or cleared in the Day-ahead Energy Market that are also included on an Emergency Load Response and Pre-Emergency Load Response registration as Full Program Option, and that have also been dispatched as part of an emergency event for the same hour (i.e., have an "overlapping dispatch hour") will be compensated for energy based on emergency energy settlement and cost allocation rules as set forth in this section and in the PJM Manuals. Overlapping dispatch hours will use shutdown costs based on what was considered for the economic event, and no balancing uplift charges will be assessed for deviations from real-time dispatch amounts or from cleared day-ahead commitments. To avoid duplicative energy payments, overlapping dispatch hours for an aggregate registration (i.e., multiple locations on the same registration) or dispatch groups

where locations on the Emergency Load Response and Pre-Emergency Load Response registration are not the same locations as those on the Economic Load Response registration will have hourly economic energy load reduction and/or hourly emergency energy load reduction prorated based on load reduction capability provided by the Curtailment Service Provider for the locations.

The Curtailment Service Provider will only submit energy settlements for Load Management Events that occur outside of the specific availability period defined in the Reliability Assurance Agreement for each Demand Resource type if the Curtailment Service Provider has confirmed that the customers on the registration did take action to reduce load or the registration reflects the entire group of mass market customers for which an energy settlement will either be submitted for all or none of the mass market customers, as approved by PJM. The Curtailment Service Provider will only submit energy settlements for tests and for each registration for Load Management Events that occur during the product specific availability period as defined for each product in the Reliability Assurance Agreement if the Curtailment Service Provider also provides associated load data for each registration in order to calculate that registration's capacity compliance.

Full Program Option participants that fail to provide a load reduction (as measured as set forth in the Reporting and Compliance provisions below) when dispatched by PJM shall be assessed penalties and/or charges as specified in Tariff, Attachment DD and the Reliability Assurance Agreement, as applicable.

During emergency conditions, costs for emergency purchases in excess of LMP are allocated among PJM Market Buyers in proportion to their increase in net purchases minus real-time dispatch reduction megawatts from the PJM energy market during the hour in the Real-time Energy Market compared to the Day-ahead Energy Market. Consistent with this pricing methodology, all charges under the Emergency Load Response and Pre-Emergency Load Response Program are allocated to purchasers of energy, in proportion to their increase in net purchases minus real-time dispatch reduction megawatts from the PJM energy market during the hour from day-ahead to real-time.

The cost of payments for Emergency Load Response and Pre-Emergency Load Response energy settlements for tests, shall be recovered from Market Participants on a ratio-share basis based on their real-time exports from the PJM Region and from Load Serving Entities on ratio-share basis based on their real-time loads in each Zone for that month where the tests were conducted, with the ratio shares determined as follows:

The ratio share for LSE i in zone z shall be RTLiz/(RTL + X)
and the ratio share for party j shall be Xj/(RTL + X).
Where:

RTL is the total real time load in all zones where Load Management was tested;
RTLiz is the real-time load for LSE i in zone z;
X is the total export quantity from PJM in that hour; and
Xj is the export quantity by party j from PJM.

Emergency Load Response and Pre-Emergency Load Response Program charges and credits will appear on the PJM Members monthly bill, as described in the ***PJM Manual for Operating Agreement Accounting and the PJM Manual for Billing.***

Attachment D

Revisions to the Operating Agreement in redlined and non-redlined format, as provided in electronic tariff filing format pursuant to Order No. 714

Revisions to the
PJM Operating Agreement

(Marked/Redline Format)

Definitions A - B

30-minute Reserve:

"30-minute Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within 30 minutes of a request from the Office of the Interconnection dispatcher, and is comprised of Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve.

30-minute Reserve Requirement:

"30-minute Reserve Requirement" shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone, as Secondary Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The 30-minute Reserve Requirement is calculated in accordance with the PJM Manuals. The requirement can be satisfied by any combination of Synchronized Reserve, Non Synchronized Reserve or Secondary Reserve resources.

Acceleration Request:

"Acceleration Request" shall mean a request pursuant to Operating Agreement, Schedule 1, section 1.9.4A and the parallel provisions of Tariff, Attachment K-Appendix, to accelerate or reschedule a transmission outage scheduled pursuant to Operating Agreement, Schedule 1, section 1.9.2 or Operating Agreement, Schedule 1, section 1.9.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.2 and Tariff, Attachment K-Appendix, section 1.9.4.

Act:

"Act" shall mean the Delaware Limited Liability Company Act, Title 6, §§ 18-101 to 18-1109 of the Delaware Code.

Active and Significant Business Interest:

"Active and Significant Business Interest" is a term that shall be used to assess the scope of a Member's PJM membership and shall be based on a Member's activity in the PJM RTO and/or Interchange Energy Markets. A Member's Active and Significant Business Interest shall: 1) be determined relative to the scope of the Member's PJM membership and activity in the PJM RTO and/or Interchange Energy Markets considering, among other things, the Member's public statements and/or regulatory filings regarding its PJM activities; and 2) reflect a substantial contributor to the Member's recent market activity, revenues, costs, investment, and/or earnings when considering the Member and its corporate affiliates' interests within the PJM footprint.

Actual MWh

"Actual MWh" is equal to the real-time output of a resource as defined by the Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Tariff,

Attachment K-Appendix, section 3.1A and parallel provisions in Operating Agreement, Schedule 1, section 3.1A.

Affected Member:

"Affected Member" shall mean a Member of PJM which as a result of its participation in PJM's markets or its membership in PJM provided confidential information to PJM, which confidential information is requested by, or is disclosed to an Authorized Person under a Non-Disclosure Agreement.

Affiliate:

"Affiliate" shall mean any two or more entities, one of which Controls the other or that are under common Control. "Control," as that term is used in this definition, shall mean the possession, directly or indirectly, of the power to direct the management or policies of an entity. Ownership of publicly-traded equity securities of another entity shall not result in Control or affiliation for purposes of the Tariff or Operating Agreement if the securities are held as an investment, the holder owns (in its name or via intermediaries) less than 10 percent (10%) of the outstanding securities of the entity, the holder does not have representation on the entity's board of directors (or equivalent managing entity) or vice versa, and the holder does not in fact exercise influence over day-to-day management decisions. Unless the contrary is demonstrated to the satisfaction of the Members Committee, Control shall be presumed to arise from the ownership of or the power to vote, directly or indirectly, ten percent or more of the voting securities of such entity.

Agreement, Operating Agreement of the PJM Interconnection, L.L.C., Operating Agreement or PJM Operating Agreement:

"Agreement," "Operating Agreement of the PJM Interconnection, L.L.C.," "Operating Agreement" or "PJM Operating Agreement" shall mean this Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. dated as of April 1, 1997 and as amended and restated as of June 2, 1997, including all Schedules, Exhibits, Appendices, addenda or supplements thereto, as amended from time to time thereafter, among the Members of PJM Interconnection L.L.C., on file with the Commission.

Annual Meeting of the Members:

"Annual Meeting of the Members" shall mean the meeting specified in Operating Agreement, section 8.3.1.

Applicable Regional Entity:

"Applicable Regional Entity" shall mean the Regional Entity for the region in which a Network Customer, Transmission Customer, New Service Customer, or Transmission Owner operates.

Applicable Standards:

"Applicable Standards" shall mean the requirements and guidelines of NERC, the Applicable Regional Entity, and the Control Area in which the Customer Facility is electrically located; the PJM Manuals; and Applicable Technical Requirements and Standards.

Associate Member:

"Associate Member" shall mean an entity that satifies the requirements of Operating Agreement, section 11.7.

Auction Revenue Rights:

"Auction Revenue Rights" or "ARRs" shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Operating Agreement, Schedule 1, section 7.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.

Auction Revenue Rights Credits:

"Auction Revenue Rights Credits" shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Authorized Commission:

"Authorized Commission" shall mean (i) a State public utility commission that regulates the distribution or supply of electricity to retail customers and is legally charged with monitoring the operation of wholesale or retail markets serving retail suppliers or customers within its State or (ii) an association or organization comprised exclusively of State public utility commissions described in the immediately preceding clause (i).

Authorized Person:

"Authorized Person" shall have the meaning set forth in Operating Agreement, section 18.17.4.

Balancing Congestion Charges:

"Balancing Congestion Charges" shall be equal to the sum of congestion charges collected from Market Participants that are purchasing energy in the Real-time Energy Market minus [the sum of congestion charges paid to Market Participants that are selling energy in the Real-time Energy Market plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, plus any charges or credits calculated pursuant to

Operating Agreement, Schedule 1, section 3.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 3.8, as applicable)].

Batch Load Economic Load Response Participant Resource:

"Batch Load Economic Load Response Participant Resource" shall mean an Economic Load Response Participant Resource that has a cyclical production process such that at most times during the process it is consuming energy, but at consistent regular intervals, ordinarily for periods of less than ten minutes, it reduces its consumption of energy for its production processes to minimal or zero megawatts.

Behind The Meter Generation:

"Behind The Meter Generation" shall refer to a generating unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of the Interconnection); provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit's capacity that is designated as a Generation Capacity Resource, or (ii) in any hour, any portion of the output of such generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

Board Member:

"Board Member" shall mean a member of the PJM Board.

Definitions E - F

Economic-based Enhancement or Expansion:

"Economic-based Enhancement or Expansion" shall mean an enhancement or expansion described in Operating Agreement, Schedule 6, section 1.5.7(b) (i) – (iii) that is designed to relieve transmission constraints that have an economic impact.

Economic Load Response Participant:

"Economic Load Response Participant" shall mean a Member or Special Member that qualifies under Operating Agreement, Schedule 1, section 1.5A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A to participate in the PJM Interchange Energy Market and/or Ancillary Services markets through reductions in demand.

Economic Maximum:

"Economic Maximum" shall mean the highest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Economic Minimum:

"Economic Minimum" shall mean the lowest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Effective Date:

"Effective Date" shall mean August 1, 1997, or such later date that FERC permits the Operating Agreement to go into effect.

Effective FTR Holder:

"Effective FTR Holder" shall mean:

(i) For an FTR Holder that is either a (a) privately held company, or (b) a municipality or electric cooperative, as defined in the Federal Power Act, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other entity that is under common ownership, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or

(ii) For an FTR Holder that is a publicly traded company including a wholly owned subsidiary of a publicly traded company, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other PJM Member has over 10% common

ownership with the FTR Holder, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or

(iii) an FTR Holder together with any other PJM Member, including also any Affiliate, subsidiary or parent of such other PJM Member, with which it shares common ownership, wholly or partly, directly or indirectly, in any third entity which is a PJM Member (e.g., a joint venture).

EIDSN, Inc.:

"EIDSN, Inc." shall mean the nonstock, nonprofit corporation, formerly known as Eastern Interconnection Data Sharing Network, Inc., or any successor thereto, that is operated primarily for the purpose of developing operating tools and the facilitation of the secure, consistent, effective, and efficient sharing of important electric transmission and operational data among Reliability Coordinators and other relevant parties to help improve electric industry operations and promote the reliable and efficient operation of the bulk electric system in the Eastern Interconnection.

Electric Distributor:

"Electric Distributor" shall mean a Member that: 1) owns or leases with rights equivalent to ownership electric distribution facilities that are used to provide electric distribution service to electric load within the PJM Region; or 2) is a generation and transmission cooperative or a joint municipal agency that has a member that owns electric distribution facilities used to provide electric distribution service to electric load within the PJM Region.

Eligible Fast-Start Resource:

"Eligible Fast-Start Resource" shall mean a Fast-Start Resource that is eligible for the application of Integer Relaxation during the calculation of Locational Marginal Prices as set forth in Tariff, Attachment K-Appendix, section 2.2.

Emergency:

"Emergency" shall mean: (i) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of emergency procedures as defined in the PJM Manuals.

Emergency Load Response Program:

"Emergency Load Response Program" shall mean the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during emergency conditions, and is described in Operating Agreement, Schedule 1, section 8 and the parallel provisions of Tariff, Attachment K-Appendix, section 8.

End-Use Customer:

"End-Use Customer" shall mean a Member that is a retail end-user of electricity within the PJM Region. For purposes of Member Committee classification, a Member that is a retail end-user that owns generation may qualify as an End-Use Customer if: (1) the average physical unforced capacity owned by the Member and its affiliates in the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the average PJM capacity obligation for the Member and its affiliates over the same time period; or (2) the average energy produced by the Member and its affiliates within the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the average energy consumed by that Member and its affiliates within the PJM region over the same time period. The foregoing notwithstanding, taking retail service may not be sufficient to qualify a Member as an End-Use Customer.

Energy Make Whole

"Energy Make Whole" shall refer to energy uplift provided to make a resource whole for costs incurred as specified in Tariff, Attachment K-Appendix, section 3.2.3 and parallel provisions in Operating Agreement, Schedule 1, section 3.2.3.

Energy Market Opportunity Cost:

"Energy Market Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of available run hours due to limitations imposed on the unit by Applicable Laws and Regulations and (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Energy Storage Resource:

"Energy Storage Resource" shall mean a resource capable of receiving electric energy from the grid and storing it for later injection to the grid that participates in the PJM Energy, Capacity and/or Ancillary Services markets as a Market Participant. Open-Loop Hybrid Resources are not Energy Storage Resources.

Energy Storage Resource Model Participant:

"Energy Storage Resource Model Participant" shall mean an Energy Storage Resource utilizing the Energy Storage Resource Participation Model.

Energy Storage Resource Participation Model:

"Energy Storage Resource Participation Model" shall mean the participation model accepted by the Commission in Docket No. ER19-469-000.

Equivalent Load:

"Equivalent Load" shall mean the sum of a Market Participant's net system requirements to serve its customer load in the PJM Region, if any, plus its net bilateral transactions.

Extended Primary Reserve Requirement:

"Extended Primary Reserve Requirement" shall equal the Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

Extended Synchronized Reserve Requirement:

"Extended Synchronized Reserve Requirement" shall equal the Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

Extended 30-minute Reserve Requirement:

"Extended 30-minute Reserve Requirement" shall equal the 30-minute Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended 30-minute Reserve Requirement is calculated in accordance with the PJM Manuals.

External Market Buyer:

"External Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for consumption by end-users outside the PJM Region, or for load in the PJM Region that is not served by Network Transmission Service.

External Resource:

"External Resource" shall mean a generation resource located outside the metered boundaries of the PJM Region.

Fast-Start Resource:

"Fast-Start Resource" shall have the meaning set forth in Tariff, Attachment K-Appendix, section 2.2A

FERC or Commission:

"FERC" or "Commission" shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over the Tariff, Operating Agreement and Reliability Assurance Agreement.

Final Offer:

"Final Offer" shall mean the offer on which a resource was dispatched by the Office of the Interconnection for a particular clock hour for an Operating Day.

Finance Committee:

"Finance Committee" shall mean the body formed pursuant to Operating Agreement, section 7.5.1.

Financial Transmission Right:

"Financial Transmission Right" or "FTR" shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2.

Financial Transmission Right Obligation:

"Financial Transmission Right Obligation" shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(b), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(c).

Financial Transmission Right Option:

"Financial Transmission Right Option" shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(c), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(c).

Flexible Resource:

"Flexible Resource" shall mean a generating resource that must have a combined Start-up Time and Notification Time of less than or equal to two hours; and a Minimum Run Time of less than or equal to two hours.

Form 715 Planning Criteria:

"Form 715 Planning Criteria" shall mean individual Transmission Owner FERC-filed planning criteria as described in Operating Agreement, Schedule 6, section 1.2(e) and filed with FERC Form No. 715 and posted on the PJM website.

FTR Holder:

"FTR Holder" shall mean the PJM Member that has acquired and possesses an FTR.

Fuel Cost Policy:

"Fuel Cost Policy" shall mean the document provided by a Market Seller to PJM and the Market Monitoring Unit in accordance with PJM Manual 15 and Operating Agreement, Schedule 2, which documents the Market Seller's method used to price fuel for calculation of the Market Seller's cost-based offer(s)for a generation resource.

Definitions S – T

Sector Votes:

"Sector Votes" shall mean the affirmative and negative votes of each sector of a Senior Standing Committee, as specified in Operating Agreement, section 8.4.

Securities:

"Securities" shall mean negotiable or non-negotiable investment or financing instruments that can be sold and bought. Securities include bonds, stocks, debentures, notes and options.

Segment:
"Segment" shall have the same meaning as described in Operating Agreement, Schedule 1, section 3.2.3(e)and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(e).

Senior Standing Committees:

"Senior Standing Committees" shall mean the Members Committee, and the Markets and Reliability Committee, as established in Operating Agreement, section 8.1 and Operating Agreement, section 8.6.

SERC:

"SERC" or "Southeastern Electric Reliability Council" shall mean the reliability council under section 202 of the Federal Power Act established pursuant to the SERC Agreement dated January 14, 1970, or any successor thereto.

Short-term Project:

"Short-term Project" shall mean a transmission enhancement or expansion with an in-service date of more than three years but no more than five years from the year in which, pursuant to Operating Agreement, Schedule 6, section 1.5.8(c), the Office of the Interconnection posts the violations, system conditions, or Public Policy Requirements to be addressed by the enhancement or expansion.

Special Member:

"Special Member" shall mean an entity that satisfies the requirements of Operating Agreement, Schedule 1, section 1.5A.02, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.02, or the special membership provisions established under the Emergency Load Response and Pre-Emergency Load Response Programs.

Spot Market Backup:

"Spot Market Backup" shall mean the purchase of energy from, or the delivery of energy to, the PJM Interchange Energy Market in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason.

Spot Market Energy:

"Spot Market Energy" shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at System Energy Prices determined as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Standing Committees:

"Standing Committees" shall mean the Members Committee, the committees established and maintained under Operating Agreement, section 8.6, and such other committees as the Members Committee may establish and maintain from time to time.

Start Fuel:

For units without a soak process, "Start Fuel" shall consist of fuel consumed from first fire of the start process to first breaker closing, plus any fuel expended from last breaker opening to shutdown.

For units with a soak process, "Start Fuel" is fuel consumed from first fire of the start process (initial reactor criticality for nuclear units) to dispatchable output (including auxiliary boiler fuel), plus any fuel expended from last breaker opening to shutdown, excluding normal plant heating/auxiliary equipment fuel requirements. Start Fuel included for each temperature state from breaker closure to dispatchable output shall not exceed the unit specific soak time period reviewed and approved as part of the unit-specific parameter process detailed in Tariff, Attachment K-Appendix, section 6.6(c) or the defaults below:

- Cold Soak Time = 0.73 * unit specific Minimum Run Time (in hours)
- Intermediate Soak Time = 0.61 * unit specific Minimum Run Time (in hours)
- Hot Soak Time = 0.43 * unit specific Minimum Run Time (in hours)

Start-Up Costs:

"Start-Up Costs" shall consist primarily of the cost of fuel, as determined by the unit's start heat input (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, emissions allowances/adders, and station service cost. Start-Up Costs can vary with the unit offline time being categorized in three unit temperature conditions: hot, intermediate and cold.

For units with a steam turbine and a soak process (nuclear, steam, and combined cycle), "Start Fuel" is fuel consumed from first fire of start process (initial reactor criticality for nuclear units):

Start-Up Costs shall mean the net unit costs from PJM's notification to the level at which the unit can follow PJM's dispatch, and from last breaker open to shutdown.

For units without a steam turbine and no soak process (engines, combustion turbines, Intermittent Resources, and Energy Storage Resources): Start-Up Costs shall mean the unit costs from PJM's notification to first breaker close and from last breaker open to shutdown.

State:

"State" shall mean the District of Columbia and any State or Commonwealth of the United States.

State Certification:

"State Certification" shall mean the Certification of an Authorized Commission, pursuant to Operating Agreement, section 18, the form of which is appended to the Operating Agreement as Operating Agreement, Schedule 10A, wherein the Authorized Commission identifies all Authorized Persons employed or retained by such Authorized Commission, a copy of which shall be filed with FERC.

State Consumer Advocate:

"State Consumer Advocate" shall mean a legislatively created office from any State, all or any part of the territory of which is within the PJM Region, and the District of Columbia established, inter alia, for the purpose of representing the interests of energy consumers before the utility regulatory commissions of such states and the District of Columbia and the FERC.

State Estimator:

"State Estimator" shall mean the computer model of power flows specified in Operating Agreement, Schedule 1, section 2.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.3.

State of Charge:

"State of Charge" shall mean the quantity of physical energy stored in an Energy Storage Resource Model Participant or in a storage component of a Hybrid Resource in proportion to its maximum State of Charge capability. State of Charge is quantified as defined in the PJM Manuals.

State of Charge Management:

"State of Charge Management" shall mean the control of State of Charge of an Energy Storage Resource Market Participant or a storage component of a Hybrid Resource using minimum and maximum discharge (and, as applicable, charge) limits, changes in operating mode (as

applicable), discharging (and, as applicable, charging) offer curves, and self-scheduling of non-dispatchable sales (and, as applicable, purchases) of energy in the PJM markets. State of Charge Management shall not interfere with the obligation of a Market Seller of an Energy Storage Resource Model Participant or of a Hybrid Resource to follow PJM dispatch, consistent with all other resources.

Station Power:

"Station Power" shall mean energy used for operating the electric equipment on the site of a generation facility located in the PJM Region or for the heating, lighting, air-conditioning and office equipment needs of buildings on the site of such a generation facility that are used in the operation, maintenance, or repair of the facility. Station Power does not include any energy (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility; (iii) used in association with restoration or black start service; or (iv) that is Direct Charging Energy.

Sub-meter:

"Sub-meter" shall mean a metering point for electricity consumption that does not include all electricity consumption for the end-use customer as defined by the electric distribution company account number. PJM shall only accept sub-meter load data from end-use customers for measurement and verification of Regulation service as set forth in the Economic Load Response rules and PJM Manuals.

Subregional RTEP Project:

"Subregional RTEP Project" shall mean a transmission expansion or enhancement rated below 230 kV which is required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.

Supplemental Project:

"Supplemental Project" shall mean a transmission expansion or enhancement that is not required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection and is not a state public policy project pursuant to Operating Agreement, Schedule 6, section 1.5.9(a)(ii). Any system upgrades required to maintain the reliability of the system that are driven by a Supplemental Project are considered part of that Supplemental Project and are the responsibility of the entity sponsoring that Supplemental Project.

Synchronized Reserve:

"Synchronized Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within ten minutes from the request of the Office of the Interconnection

dispatcher, and is provided by equipment that is electrically synchronized to the Transmission System.

Synchronized Reserve Event:

"Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources and/or Economic Load Response Participant resources able, assigned or self-scheduled to provide Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes, to increase the energy output or reduce load by a directed amount of the assigned or self-scheduled Synchronized Reserve.

Synchronized Reserve Requirement:

"Synchronized Reserve Requirement" shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Synchronized Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals. This requirement can only be satisfied by Synchronized Reserve resources.

System:

"System" shall mean the interconnected electric supply system of a Member and its interconnected subsidiaries exclusive of facilities which it may own or control outside of the PJM Region. Each Member may include in its system the electric supply systems of any party or parties other than Members which are within the PJM Region, provided its interconnection agreements with such other party or parties do not conflict with such inclusion.

System Energy Price:

"System Energy Price" shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Target Allocation:

"Target Allocation" shall mean the allocation of Transmission Congestion Credits as set forth in Operating Agreement, Schedule 1, section 5.2.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.3 or the allocation of Auction Revenue Rights Credits as set forth in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Third Party Request:

"Third Party Request" shall mean any request or demand by any entity upon an Authorized Person or an Authorized Commission for release or disclosure of confidential information

provided to the Authorized Person or Authorized Commission by the Office of the Interconnection or the Market Monitoring Unit. A Third Party Request shall include, but shall not be limited to, any subpoena, discovery request, or other request for confidential information made by any: (i) federal, state, or local governmental subdivision, department, official, agency or court, or (ii) arbitration panel, business, company, entity or individual.

Tie Line:

"Tie Line" shall have the same meaning provided in the Open Access Transmission Tariff.

Total Lost Opportunity Cost Offer:

"Total Lost Opportunity Cost Offer" shall mean the applicable offer used to calculate lost opportunity cost credits. For pool-scheduled resources specified in PJM Operating Agreement, Schedule 1, section 3.2.3(f-1) and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-1), the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the greater of the Committed Offer or last Real-Time Offer submitted for the offer on which the resource was committed in the Day-ahead Energy Market for each hour in an Operating Day. For all other pool-scheduled resources, the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the offer curve associated with the greater of the Committed Offer or Final Offer for each hour in an Operating Day. For self-scheduled generation resources, the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, where for self-scheduled generation resources (a) operating pursuant to a cost-based offer, the applicable offer curve shall be the greater of the originally submitted cost-based offer or the cost-based offer that the resource was dispatched on in real-time; or (b) operating pursuant to a market-based offer, the applicable offer curve shall be determined in accordance with the following process: (1) select the greater of the cost-based day-ahead offer and updated costbased Real-time Offer; (2) for resources with multiple cost-based offers, first, for each cost-based offer select the greater of the day-ahead offer and updated Real-time Offer, and then select the lesser of the resulting cost-based offers; and (3) compare the offer selected in (1), or for resources with multiple cost-based offers the offer selected in (2), with the market-based day-ahead offer and the market-based Real-time Offer and select the highest offer.

~~**Total Operating Reserve Offer:**~~

~~"Total Operating Reserve Offer" shall mean the applicable offer used to calculate Operating Reserve credits. The Total Operating Reserve Offer shall equal the sum of all individual Real-time Settlement Interval energy offers, inclusive of Start-Up Costs (shut-down costs for Demand Resources) and No-load Costs, for every Real-time Settlement Interval in a Segment, integrated under the applicable offer curve up to the applicable megawatt output as further described in the PJM Manuals. The applicable offer used to calculate day-ahead Operating Reserve credits shall be the Committed Offer, and the applicable offer used to calculate balancing Operating Reserve credits shall be lesser of the Committed Offer or Final Offer for each hour in an Operating Day.~~

Tracking Ramp Limited Desired

"Tracking Ramp Limited Desired" shall mean the desired MW or MWh calculated pursuant to Tariff, Attachment K-Appendix, section 3.2.3(e-1) and parallel provisions in Operating Agreement, Schedule 1, section 3.2.3(e-1).

Transmission Congestion Charge:

"Transmission Congestion Charge" shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses, which shall be calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.1, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.1.

Transmission Congestion Credit:

"Transmission Congestion Credit" shall mean the allocated share of total Transmission Congestion Charges credited to each FTR Holder, calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.

Transmission Customer:

"Transmission Customer" shall have the meaning set forth in the PJM Tariff.

Transmission Facilities:

"Transmission Facilities" shall mean facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERC's Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the PJM Region transmission system and integrated into the planning and operation of the PJM Region to serve all of the power and transmission customers within the PJM Region.

Transmission Forced Outage:

"Transmission Forced Outage" shall mean an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the PJM Manuals. A removal from service of a transmission facility at the request of the Office of the Interconnection to improve transmission capability shall not constitute a Forced Transmission Outage.

Transmission Loading Relief:

"Transmission Loading Relief" shall mean NERC's procedures for preventing operating security limit violations, as implemented by PJM as the security coordinator responsible for maintaining transmission security for the PJM Region.

Transmission Loss Charge:

"Transmission Loss Charge" shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Operating Agreement, Schedule 1, section 5, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.

Transmission Operator:

"Transmission Operator" shall have the same meaning set forth in the NERC Glossary of Terms used in NERC Reliability Standards.

Transmission Owner:

"Transmission Owner" shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

Transmission Owner Upgrade:

"Transmission Owner Upgrade" shall mean an upgrade to a Transmission Owner's own transmission facilities, which is an improvement to, addition to, or replacement of a part of, an existing facility and is not an entirely new transmission facility.

Transmission Planned Outage:

"Transmission Planned Outage" shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in Operating Agreement, Schedule 1, and the parallel provisions of Tariff, Attachment K-Appendix, or the PJM Manuals.

Turn Down Ratio:

"Turn Down Ratio" shall mean the ratio of a generating unit's economic maximum megawatts to its economic minimum megawatts.

18.17 Confidentiality.

18.17.1 Party Access.

(a) No Member shall have a right hereunder to receive or review any documents, data or other information of another Member, including documents, data or other information provided to the Office of the Interconnection, to the extent such documents, data or information have been designated as confidential pursuant to the procedures adopted by the Office of the Interconnection and/or the Market Monitoring Unit or to the extent that they have been designated as confidential by such other Member; provided, however, a Member may receive and review any composite documents, data and other information that may be developed based on such confidential documents, data or information if the composite does not disclose any individual Member's confidential data or information.

(b) Except as may be provided in this Agreement or in the PJM Open Access Transmission Tariff, the Office of the Interconnection shall not disclose to its Members or to third parties, any documents, data, or other information of a Member or entity applying for Membership, to the extent such documents, data, or other information has been designated confidential pursuant to the procedures adopted by the Office of the Interconnection or by such Member or entity applying for membership; provided that nothing contained herein shall prohibit the Office of the Interconnection from providing any such confidential information to its agents, representatives, or contractors to the extent that such person or entity is bound by an obligation to maintain such confidentiality; provided further that nothing contained herein shall prohibit the Office of the Interconnection from providing Member confidential information to the NERC, EIDSN, Inc., any Applicable Regional Entity, any Reliability Coordinator, any Transmission Operator, and the agents, representatives, or contractors of such entity, to the extent that (i) the Office of the Interconnection determines in its reasonable discretion that the exchange of such information is required to enhance and/or maintain reliability within the Members' Applicable Regional Entities and their neighboring Regional Entities, or within the region of any Reliability Coordinator, (ii) such entity is bound by a written agreement to maintain such confidentiality, and (iii) the Office of the Interconnection has notified the affected party of its intention to release such information no less than five Business Days prior to the release. The Office of the Interconnection, its designated agents, representatives, and contractors shall maintain as confidential the electronic tag ("e-Tag") data of an e-Tag Author or Balancing Authority (defined as those terms are used in FERC Order No. 771) to the same extent as Member data under this section 18.17. Nothing contained herein shall prohibit the Office of the Interconnection or its designated agents, representatives, or contractors from providing to another Regional Transmission Organization ("RTO") or Independent System Operator ("ISO"), upon their request, the e-Tags of an e-Tag Author or Balancing Authority for intra-PJM Region transactions and interchange transactions scheduled to flow into, out of or through the PJM Region, to the extent such RTO or ISO has requested such information as part of its investigation of possible market violations or market design flaws, and to the extent that such RTO or ISO is bound by a tariff provision requiring that the e-Tag data be maintained as confidential or, in the absence of a tariff requirement governing confidentiality, a written agreement with the Office of the Interconnection consistent with FERC Order No. 771 and any clarifying orders and implementing regulations. The Office of the Interconnection shall collect and use confidential

information only in connection with its authority under this Agreement and the Open Access Transmission Tariff and the retention of such information shall be in accordance with the Office of the Interconnection's data retention policies.

(c) Nothing contained herein shall prevent the Office of the Interconnection from releasing a Member's confidential data or information to a third party provided that the Member has delivered to the Office of the Interconnection and/or the Market Monitoring Unit specific, written authorization for such release setting forth the data or information to be released, to whom such release is authorized, and the period of time for which such release shall be authorized. The Office of the Interconnection shall limit the release of a Member's confidential data or information to that specific authorization received from the Member. Nothing herein shall prohibit a Member from withdrawing such authorization upon written notice to the Office of the Interconnection, who shall cease such release as soon as practicable after receipt of such withdrawal notice.

(d) Reciprocal provisions to this section 18.17.1, Operating Agreement, section18.17.2, Operating Agreement, section 18.17.3, Operating Agreement, section18.17.4 and Operating Agreement, section 18.17.5 , delineating the confidentiality requirements of PJM's Market Monitoring Unit, are set forth in Tariff, Attachment M – Appendix, section I.

(e) Notwithstanding anything to the contrary in this Agreement or in the PJM Tariff, the Office of the Interconnection shall post the following on its website:

(i) the non-aggregated bid data and Offer Data submitted by Market Participants (for participation on the PJM Interchange Energy Market) approximately four months after the bid or offer was submitted to the Office of the Interconnection to allow the tracking of Market Participants' non-aggregated bids and offers over time as required by FERC Order No. 719. However, to protect the confidential, market sensitive and/or proprietary bidding strategies of Market Participants as well as the identity of Market Participants from being discernible from the published data, the posted information will not reveal the (a) name of the resource, (b) characteristics of a specific resource, (c) identity of the load, (d) name of the individual or entity submitting the data, (e) identity of the resource owner, or (f) location of the resource at a level lower than its Zone. The Office of the Interconnection also reserves the right to take any other precautionary measures that it deems appropriate to preserve the confidential, market sensitive and/or proprietary bidding strategies of Market Participants to the extent not specifically set forth herein.

(ii) Within 20 calendar days after the end of each month, (a) the total daily uplift credits by Zone as set forth in Tariff, Attachment J, and RAA, Schedule 15, and applicable uplift charge codes (including lost opportunity cost contained within ~~operating reserves~~energy uplift) and (b) the total daily uplift charges by applicable PJM Region or Zone, as set forth in Tariff, Attachment J and RAA, Schedule 15, and applicable uplift charge codes along with relevant subcategories by which they are allocated. The Office of the Interconnection shall incorporate the best available information at the time the posting is created.

(iii) Within 90 calendar days after the end of each month, the name of each generation resource unit and amount of uplift credit payments by applicable uplift charge codes (including lost opportunity cost contained within ~~operating reserves~~energy uplift, but excluding Black Start Service) for each resource unit that received uplift credits in that month. For Demand Resources or Economic Load Response Participants, the Office of Interconnection shall post, within 90 calendar days after the end of each month, the individual resource identification number associated with the Demand Resource or Economic Load Response Participant's relevant dispatch group or registration, the name of the associated Curtailment Service Provider, the Zone and energy pricing point used to settle the Demand Resource or Economic Load Response Participant's dispatch group or registration, and the corresponding amount of uplift credits by applicable uplift charge codes for the dispatch group or registration that received uplift credits in that month. The Office of Interconnection shall incorporate the best available information at the time the posting is created.

(iv) Within 30 calendar days after the end of each month, each Operator-initiated Commitment listing the size of the commitment in megawatts (where megawatts are equal to the economic maximum), Zone (as set forth in Tariff, Attachment J and RAA, Schedule 15), commitment reason, and commitment start time. Commitment reasons shall include, but are not limited to, system wide capacity, constraint management, and voltage support.

(f) To the extent permitted pursuant to 18 C.F.R. §38.2 (or successor provisions), nothing contained herein shall prohibit the Office of the Interconnection from sharing non-public, operational information with an interstate natural gas pipeline operator for the purpose of promoting reliable service or operational planning. Further, the Office of the Interconnection shall be permitted to share non-public, operational information with natural gas local distribution companies and/or intrastate natural gas pipeline operators, as appropriate, for the purpose of promoting reliable service or operational planning, provided that such party has acknowledged, in writing, that it shall not disclose, or use anyone as a conduit for disclosure of, non-public, operational information received from the Office of Interconnection to a third party or in an unduly discriminatory or preferential manner or to the detriment of any natural gas and/or electric market. Such non-public, operational information received from natural gas local distribution companies and/or intrastate natural gas pipeline operators pursuant to this section will be subject to the confidentiality provisions set forth in this section 18.17.

18.17.2 Required Disclosure.

(a) Notwithstanding anything in the foregoing section to the contrary, and subject to the provisions of section 18.17.3 below, if the Office of the Interconnection is required by applicable law, order, or in the course of administrative or judicial proceedings, to disclose to third parties, information that is otherwise required to be maintained in confidence pursuant to this Agreement, the Office of the Interconnection or its designated agents, representatives, or contractors may make disclosure of such information; provided, however, that as soon as the Office of the Interconnection learns of the disclosure requirement and prior to it or its designated agents, representatives, or contractors making disclosure, the Office of the Interconnection shall notify the affected Member or Members of the requirement and the terms thereof and the affected Member or Members may direct, at their sole discretion and cost, any challenge to or

defense against the disclosure requirement. The Office of the Interconnection shall cooperate with such affected Members to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. The Office of the Interconnection shall cooperate with the affected Members to obtain proprietary or confidential treatment of such information by the person to whom such information is disclosed prior to any such disclosure.

(b) Nothing in this section 18.17 shall prohibit or otherwise limit the Office of the Interconnection's use of information covered herein if such information was: (i) previously known to the Office of the Interconnection without an obligation of confidentiality; (ii) independently developed by or for the Office of the Interconnection using non-confidential information; (iii) acquired by the Office of the Interconnection from a third party which is not, to the Office of the Interconnection's knowledge, under an obligation of confidence with respect to such information; (iv) which is or becomes publicly available other than through a manner inconsistent with this section 18.17.

(c) The Office of the Interconnection shall impose on any contractors retained to provide technical support or otherwise to assist with the implementation or administration of this Agreement or of the Open Access Transmission Tariff a contractual duty of confidentiality consistent with this Agreement. A Member shall not be obligated to provide confidential or proprietary information to any contractor that does not assume such a duty of confidentiality, and the Office of the Interconnection shall not provide any such information to any such contractor without the express written permission of the Member providing the information.

18.17.3 Disclosure to FERC and CFTC.

(a) Notwithstanding anything in this section to the contrary, if the FERC, the Commodity Futures Trading Commission ("CFTC"), or the staff of those commissions, during the course of an investigation or otherwise, requests information from the Office of the Interconnection that is otherwise required to be maintained in confidence pursuant to this Agreement, the Office of the Interconnection shall provide the requested information to the FERC, CFTC or their respective staff, within the time provided for in the request for information. In providing the information to the FERC or its staff, the Office of the Interconnection may request, consistent with 18 C.F.R. §§ 1b.20 and 388.112, or to the CFTC or its staff, the Office of the Interconnection may request, consistent with 17 C.F.R. §§ 11.3 and 145.9, that the information be treated as confidential and non-public by the respective commission and its staff and that the information be withheld from public disclosure. The Office of the Interconnection shall promptly notify any affected Member(s) if the Office of the Interconnection receives from the FERC, CFTC or their staff written notice that the commission has decided to release publicly, or has asked for comment on whether such commission should release publicly, confidential information previously provided to a commission by the Office of the Interconnection.

(b) Section 18.17.3(a) above shall not apply to requests for production of information under Subpart D of the FERC's Rules of Practice and Procedure (18 CFR Part 385) in proceedings before FERC and its administrative law judges. In all such proceedings, the Office of the Interconnection shall follow the procedures in section 18.17.2 above.

(c) Pursuant to the FERC Order No. 760, as codified under 18 C.F.R. § 35.28(g)(4), to the extent that the Office of the Interconnection already collects such data described in Order No. 760, the Office of the Interconnection shall electronically deliver to the FERC, on an ongoing basis and in a form and manner consistent with its own collection of data and in a form and manner acceptable to the FERC, data related to the markets that the Office of the Interconnection administers. Section 18.17.3(a) above shall not apply to data supplied to the FERC under this subsection (c) to satisfy the FERC Order No. 760 requirements.

(d) Pursuant to the FERC Order No. 771 and any clarifying orders, as codified under 18 C.F.R. § 366.2(d), the Office of the Interconnection shall ensure that FERC is included as an addressee on all e-Tags for transactions that sink within the PJM Region.

18.17.4 Disclosure to Authorized Commissions.

(a) Notwithstanding anything in this section to the contrary, the Office of the Interconnection shall disclose confidential information, otherwise required to be maintained in confidence pursuant to this Agreement, to an Authorized Commission under the following conditions:

(i) The Authorized Commission has provided the FERC with a properly-executed Certification in the form attached hereto as Operating Agreement, Schedule 10A. Upon receipt of the Authorized Commission's Certification, the FERC shall provide public notice of the Authorized Commission's filing pursuant to 18 C.F.R. § 385.2009. If any interested party disputes the accuracy and adequacy of the representations contained in the Authorized Commission's Certification, that party may file a protest with the Commission within 14 days of the date of such notice, pursuant to 18 C.F.R. § 385.211. The Authorized Commission may file a response to any such protest within seven days. Each party shall bear its own costs in connection with such a FERC protest proceeding. If there are material changes in law that affect the accuracy and adequacy of the representations in the Certification filed with the Commission, the Authorized Commission shall, within thirty (30) days, submit an amended Certification identifying such changes. Any such amended Certification shall be subject to the same procedures for comment and review by the Commission as set forth above in this paragraph.

The Office of the Interconnection may not disclose data to an Authorized Commission during the Commission's consideration of the Certification and any filed protests. If the Commission does not act upon an Authorized Commission's Certification within 90 days of the date of filing, the Certification shall be deemed approved and the Authorized Commission shall be permitted to receive confidential information pursuant to this section. In the event that an interested party protests the Authorized Commission's Certification and the Commission approves the Certification, that party may not challenge any Information Request made by the Authorized Commission on the grounds that the Authorized

Commission is unable to protect the confidentiality of the information requested, in the absence of a showing of changed circumstances.

(ii) Any confidential information provided to an Authorized Commission pursuant to this section shall not be further disclosed by the recipient Authorized Commission except by order of the Commission.

(iii) The Office of the Interconnection shall be expressly entitled to rely upon such Authorized Commission Certifications in providing confidential information to the Authorized Commission, and shall in no event be liable, or subject to damages or claims of any kind or nature hereunder, due to the ineffectiveness or inaccuracy of such Authorized Commission Certifications.

(iv) The Authorized Commission may provide confidential information obtained from the Office of the Interconnection to such of its employees, attorneys and contractors as needed to examine or handle that information in the course and scope of their work on behalf of the Authorized Commission, provided that (a) the Authorized Commission has internal procedures in place, pursuant to the Certification, to ensure that each person receiving such information agrees to protect the confidentiality of such information (such employees, attorneys or contractors to be defined hereinafter as "Authorized Persons"); (b) the Authorized Commission provides, pursuant to the Certification, a list of such Authorized Persons to the Office of the Interconnection and the Market Monitoring Unit and updates such list, as necessary, every ninety (90) days; and (c) any third-party contractors provided access to confidential information sign a non-disclosure agreement in the form attached hereto as Operating Agreement, Schedule 10 before being provided access to any such confidential information.

(v) The Office of the Interconnection shall maintain a schedule of all Authorized Persons and the Authorized Commissions they represent, which shall be made publicly available on its website, or by written request. Such schedule shall be compiled by the Office of the Interconnection, based on information provided by any Authorized Commission. The Office of the Interconnection shall update the schedule promptly upon receipt of information from an Authorized Commission, but shall have no obligation to verify or corroborate any such information, and shall not be liable or otherwise responsible for any inaccuracies in the schedule due to incomplete or erroneous information conveyed to and relied upon by the Office of the Interconnection in the compilation and/or maintenance of the schedule.

(b) The Office of the Interconnection may, in the course of discussions with an Authorized Person, orally disclose information otherwise required to be maintained in confidence, without

the need for a prior Information Request. Such oral disclosures shall provide enough information to enable the Authorized Person or the Authorized Commission with which that Authorized Person is associated to determine whether additional Information Requests are appropriate. The Office of the Interconnection will not make any written or electronic disclosures of confidential information to the Authorized Person pursuant to this section 18.17.4(b). In any such discussions, the Office of the Interconnection shall ensure that the individual or individuals receiving such confidential information are Authorized Persons as defined herein, orally designate confidential information that is disclosed, and refrain from identifying any specific Affected Member whose information is disclosed. The Office of the Interconnection shall also be authorized to assist Authorized Persons in interpreting confidential information that is disclosed. The Office of the Interconnection shall provide any Affected Member with oral notice of any oral disclosure immediately, but not later than one (1) Business Day after the oral disclosure. Such oral notice to the Affected Member shall include the substance of the oral disclosure, but shall not reveal any confidential information of any other Member and must be received by the Affected Member before the name of the Affected Member is released to the Authorized Person; provided however, disclosure of the identity of the Affected Party must be made to the Authorized Commission with which the Authorized Person is associated within two (2) Business Days of the initial oral disclosure.

(c) As regards Information Requests:

(i) Information Requests to the Office of the Interconnection and/or Market Monitoring Unit by an Authorized Commission shall be in writing, which shall include electronic communications, addressed to the Office of the Interconnection, and shall: (a) describe the information sought in sufficient detail to allow a response to the Information Request; (b) provide a general description of the purpose of the Information Request; (c) state the time period for which confidential information is requested; and (d) re-affirm that only Authorized Persons shall have access to the confidential information requested. The Office of the Interconnection shall provide an Affected Member with written notice, which shall include electronic communication, of an Information Request by an Authorized Commission as soon as possible, but not later than two (2) Business Days after the receipt of the Information Request.

(ii) Subject to the provisions of section (c)(iii) below, the Office of the Interconnection shall supply confidential information to the Authorized Commission in response to any Information Request within five (5) Business Days of the receipt of the Information Request, to the extent that the requested confidential information can be made available within such period; provided however, that in no event shall confidential information be released prior to the end of the fourth (4th) Business Day without the express consent of the Affected Member. To the extent that the Office of the Interconnection cannot reasonably prepare and deliver the requested confidential information within such five (5) day period, it shall, within such period, provide the Authorized Commission with a written schedule

for the provision of such remaining confidential information. Upon providing confidential information to the Authorized Commission, the Office of the Interconnection shall either provide a copy of the confidential information to the Affected Member(s), or provide a listing of the confidential information disclosed; provided, however, that the Office of the Interconnection shall not reveal any Member's confidential information to any other Member.

(iii) Notwithstanding section (c)(ii) above, should the Office of the Interconnection or an Affected Member object to an Information Request or any portion thereof, any of them may, within four (4) Business Days following the Office of the Interconnection's receipt of the Information Request, request, in writing, a conference with the Authorized Commission to resolve differences concerning the scope or timing of the Information Request; provided, however, nothing herein shall require the Authorized Commission to participate in any conference. Any party to the conference may seek assistance from FERC staff in resolution of the dispute or terminate the conference process at any time. Should such conference be refused or terminated by any participant or should such conference not resolve the dispute, then the Office of the Interconnection or the Affected Member may file a complaint with the Commission pursuant to Rule 206 objecting to the Information Request within ten (10) Business Days following receipt of written notice from any conference participant terminating such conference. Any complaints filed at FERC objecting to a particular Information Request shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding. The grounds for such a complaint shall be limited to the following: (a) the Authorized Commission is no longer able to preserve the confidentiality of the requested information due to changed circumstances relating to the Authorized Commission's ability to protect confidential information arising since the filing of or rejection of a protest directed to the Authorized Commission's Certification; (b) complying with the Information Request would be unduly burdensome to the complainant, and the complainant has made a good faith effort to negotiate limitations in the scope of the requested information; or (c) other exceptional circumstances exist such that complying with the Information Request would result in harm to the complainant. There shall be a presumption that "exceptional circumstances," as used in the prior sentence, does not include circumstances in which an Authorized Commission has requested wholesale market data (or Market Monitoring Unit workpapers that support or explain conclusions or analyses) generated in the ordinary course and scope of the operations of the Office of the Interconnection and/or the Market Monitoring Unit. There shall be a presumption that circumstances in which an Authorized Commission has requested personnel files, internal emails and internal company memos, analyses and related work product constitute "exceptional circumstances"

as used in the prior sentence. If no complaint challenging the Information Request is filed within the ten (10) day period defined above, the Office of the Interconnection shall utilize its best efforts to respond to the Information Request promptly. If a complaint is filed, and the Commission does not act on that complaint within ninety (90) days, the complaint shall be deemed denied and the Office of Interconnection shall use its best efforts to respond to the Information Request promptly.

(iv) Any Authorized Commission may initiate appropriate legal action at FERC within ten (10) Business Days following receipt of information designated as "Confidential," challenging such designation. Any complaints filed at FERC objecting to the designation of information as "Confidential" shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding. The party filing such a complaint shall be required to prove that the material disclosed does not merit "Confidential" status because it is publicly available from other sources or contains no trade secret or other sensitive commercial information (with "publicly available" not being deemed to include unauthorized disclosures of otherwise confidential data).

(d) In the event of any breach of confidentiality of information disclosed pursuant to an Information Request by an Authorized Commission or Authorized Person:

(i) The Authorized Commission or Authorized Person shall promptly notify the Office of the Interconnection, who shall, in turn, promptly notify any Affected Member of any inadvertent or intentional release, or possible release, of confidential information provided pursuant to this section.

(ii) The Office of the Interconnection shall terminate the right of such Authorized Commission to receive confidential information under this section upon written notice to such Authorized Commission unless: (i) there was no harm or damage suffered by the Affected Member; or (ii) similar good cause is shown. Any appeal of the Office of the Interconnection's and/or the Market Monitoring Unit's actions under this section shall be to FERC. An Authorized Commission shall be entitled to reestablish its certification as set forth in section 18.17.4(a) above by submitting a filing with the Commission showing that it has taken appropriate corrective action. If the Commission does not act upon an Authorized Commission's re-certification filing with sixty (60) days of the date of the filing, the re-certification shall be deemed approved and the Authorized Commission shall be permitted to receive confidential information pursuant to this section.

(iii) The Office of the Interconnection and/or the Affected Member shall have the right to seek and obtain at least the following types of relief: (a) an

order from FERC requiring any breach to cease and preventing any future breaches; (b) temporary, preliminary, and/or permanent injunctive relief with respect to any breach; and (c) the immediate return of all confidential information to the Office of the Interconnection.

(iv) No Authorized Person or Authorized Commission shall have responsibility or liability whatsoever under this section for any and all liabilities, losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with the release of confidential information to persons not authorized to receive it, provided that such Authorized Person is an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release. Nothing in this section (d)(iv) is intended to limit the liability of any person who is not an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release for any and all economic losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with such unauthorized release.

(v) Any dispute or conflict requesting the relief in section (d)(ii) or (d)(iii)(a) above, shall be submitted to FERC for hearing and resolution. Any dispute or conflict requesting the relief in section (d)(iii)(c) above may be submitted to FERC or any court of competent jurisdiction for hearing and resolution.

18.17.5 [Reserved]

18.17.6 Disclosure of EMS and Transmission System Data to Transmission Owners on PJM EMS Terminal and Via Other Reliability or Situational Awareness Tools

(a) While the Office of the Interconnection has overall responsibility for power system reliability in the PJM Region, Transmission Owners within the PJM Region perform specified reliability functions with respect to their individual Transmission Facilities and distribution systems. In order to facilitate reliable operations between the Office of the Interconnection and the Transmission Owners, the Office of the Interconnection may, without written authorization from any Member, install a read-only terminal, or allow the Transmission Owner through a secure communication channel, in any Transmission Owner's secure control room facility to access the Office of the Interconnection's Energy Management System (EMS), or its other reliability or situational awareness tools, and the associated transmission and generation data under the terms and conditions set forth in this section 18.17.6.

(b) The data and information produced by the EMS or other situational awareness tool, are confidential and/or commercially sensitive because they will display the real-time status of electric transmission lines and generation facilities, the disclosure of which could impact the market and the commercial interests of its participants. In addition, the responsive information will contain detailed information about real-time grid conditions, transmission lines, power

flows, and outages, which may fall within the definition of Critical Energy Infrastructure Information (CEII) as set forth in 18 CFR § 388.113. The Office of the Interconnection shall not release any generator cost, price or other market information without written authorization pursuant to section 18.17.1 (c) above unless otherwise provided for under this Agreement. The only generator information that will be made available on the read-only PJM EMS terminal is real-time MW/MVAR output and Minimum/Maximum MW Range. The transmission system information that may be made available via a reliability or situational awareness tool is limited to geospatial locations and other real-time operational data.

(c) The confidential or CEII information provided to the Transmission Owner on a read-only PJM EMS terminal or via another reliability or situational awareness tool shall only be held in the secure control room facility of the Transmission Owner. Such data shall be used for informational and operational purposes within the control room by transmission function employees as defined in the FERC's rules and regulations, 18 C.F.R. § 358. No "screen-scraping" or other data transfer of information from the read-only terminal or other situational awareness tool to other Transmission Owner systems or databases shall be permitted. No storage of information from the read-only terminal or other reliability or situational awareness tool shall be permitted. The data shall be held confidential within the transmission function environment and not be disclosed to other personnel within the Transmission Owners' company, subsidiaries, marketing organizations, energy affiliates or independent third parties. The Transmission Owner may use the confidential or CEII information only for the purpose of performing Transmission Owner's reliability function and shall not otherwise use the confidential information for its own benefit or for the benefit of any other person.

(d) In the event of any breach:

(i) The Transmission Owner(s) that caused the breach, or whose confidential information or CEII was used or disseminated beyond the limitations specified herein shall promptly notify the Office of the Interconnection, which shall, in turn, promptly notify FERC and any affected Member(s) of any inadvertent or intentional release, or possible release, of confidential or CEII information disclosed as provided above.

(ii) The Office of the Interconnection shall terminate all rights of the Transmission Owner to receive confidential or CEII information as provided in this section 18.17.6; provided, however, that the Office of the Interconnection may restore a Transmission Owners' status after consulting with the affected Member(s) whose confidential or CEII information was used or disseminated beyond the limitations specified herein and to the extent that: (a) the Office of the Interconnection determines that the disclosure was not due to the intentional, reckless or negligent action or omission of the authorized transmission function employee; (b) there were no harm or damages suffered by the affected Member(s); or (c) similar good cause shown. Any appeal of the Office of the Interconnection's actions under this section shall be to FERC.

(iii) The Office of the Interconnection and/or the affected Member(s) shall have the right to seek and obtain at least the following types of relief: (a) an order from FERC requiring any breach to cease and preventing any future breaches; (b) temporary, preliminary, and/or permanent injunctive relief and/or damages with respect to any breach; and (c) the immediate return of all confidential or CEII information to the Office of the Interconnection.

(iv) Any dispute or conflict requesting the relief in section (d)(ii) or (d)(iii)(a) above, shall be submitted to FERC for hearing and resolution. Any dispute or conflict requesting the relief in section (d)(iii)(b) and (c) above may be submitted to FERC or any court of competent jurisdiction for hearing and resolution.

18.17.7 Disclosure of Generator Data to Transmission Owners

(a) In order to facilitate reliable operations between the Office of the Interconnection and the Transmission Owners, the Office of the Interconnection may, without written authorization from any Member, provide to each Transmission Owner upon the Transmission Owner's request the following confidential generator information for any generator that: (1) is or will be modeled within the Transmission Owner's energy management system; or (2) is or will be identified in a Transmission Owner's restoration plan:

(i) real-time unit status;

(ii) real-time megawatt output;

(iii) real-time megavolt amperes reactive ("MVAR");

(iv) the start date, start time, stop date, and stop time for the unit's scheduled outages;

(v) the unit's reactive capability curve; and

(vi) data provided for Transmission Owner use for system restoration planning purposes only, including but not limited to the unit's start-up times, ramp rate, start-up auxiliary load profile and emergency low-load operation capabilities.

(b) In order to facilitate reliable operations between the Office of the Interconnection and the Transmission Owners, the Office of the Interconnection may, without written authorization from any Member, provide to each Transmission Owner the following generator information:

(i) forecasted unit status;

(ii) forecasted megawatt output;

(iii) the start date, start time, stop date, and stop time for the information in this section 18.17.7 (b)(i) and 18.17.7 (b)(ii);

(iv) the Zone in which the generator resides; and

(v) generator operating parameters including, but not limited, to each unit's start-up times, ramp rate, Minimum Down Time, and Minimum Run Time.

(c) The Office of the Interconnection will provide the data in section 18.17.7(a) and (b) only where it possesses such data. The Office of the Interconnection shall provide this confidential information only to transmission function employees, as transmission function employee is defined in section 18 C.F.R. § 358 of the FERC rules and regulations.

(d) A Transmission Owner may only use the generator data provided under section 18.17.7(a) and (b) above for the purpose of executing the Transmission Owner's reliability function and transmission function, as transmission function is defined in section 18 C.F.R. § 358 of the FERC rules and regulations, and shall not otherwise use the confidential information for its own benefit or the benefit of any other person. A Transmission Owner may disclose the generator data obtained under section 18.17.7(a) and (b) above only to the Transmission Owner's transmission function employees whose access to such data is necessary to perform the Transmission Owner's transmission functions. Transmission Owners shall not disclose the generator data obtained under section 18.17.7(a) and (b) above to any person, including marketing function employees as defined in section 18 C.F.R. § 358 of the FERC rules and regulations, except as permitted under this section 18.17.7.

(e) Each Transmission Owner shall protect and keep confidential all the information it receives from the Office of the Interconnection pursuant to this section 18.17.7. It may, copy, post, distribute, disclose or disseminate the data obtained pursuant to section 18.17.7(a) and (b) above only in the following manner. Each Transmission Owner may make a limited number of copies of written or electronic materials to enable the Transmission Owner to adequately use the information obtained pursuant to section 18.17.7(a) and (b) above within the terms and conditions of this section of this Agreement. If the Transmission Owner prints or electronically conveys any information in obtained pursuant to section 18.17.7(a) and (b) above, it shall protect each copy in accordance with this section 18.17.7 and mark each copy as "Confidential Information."

(f) The Transmission Owner shall destroy all information obtained under section 18.17.7(a) and (b) above upon the completion of the use of such information for the purpose of performing Transmission Owner's transmission functions, as transmission functions is defined in section 18 C.F.R. § 358 of the FERC rules and regulations.

(g) A Transmission Owner shall be responsible for the breach of this section 18.17.7 by any of its employees or representatives. In the event of any breach by the Transmission Owner of

this section 18.17.7 by any of its employees or representatives, section 18.17.6(d) shall apply to the release of the confidential information.

18.17.8 Disclosure of Credit-Related Information to FERC-Jurisdictional RTOs and ISOs

(a) Notwithstanding anything to the contrary in this Operating Agreement or in the Tariff, the Office of the Interconnection is permitted to share credit-related information of Members, Market Participants, and Applicants, including, without limitation, information of the respective Affiliates of the foregoing, with other FERC-jurisdictional RTOs and ISOs for the purpose of credit risk management and mitigation.

(b) The Office of the Interconnection is permitted to use credit-related information received from other FERC-jurisdictional RTOs and ISOs to the same extent and for the same purposes that it may use credit-related information received from its Members, Market Participants, and Applicants. The Office of the Interconnection will treat credit-related information received from other FERC-jurisdictional RTOs and ISOs as confidential information to the same extent as it would treat such information if it were received directly from one of its Members, Market Participants or Applicants.

1.10 Scheduling.

1.10.1 General.

(a) The Office of the Interconnection shall administer scheduling processes to implement a Day-ahead Energy Market and a Real-time Energy Market. PJMSettlement shall be the Counterparty to the purchases and sales of energy that clear the Day-ahead Energy Market and the Real-time Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a Generating Market Buyer's self-schedule or self-supply of its generation resources up to that Generating Market Buyer's Equivalent Load.

(b) The Day-ahead Energy Market shall enable Market Participants to purchase and sell energy through the PJM Interchange Energy Market at Day-ahead Prices and enable Transmission Customers to reserve transmission service with Transmission Congestion Charges and Transmission Loss Charges based on locational differences in Day-ahead Prices. Up-to Congestion Transactions submitted in the Day-ahead Energy Market shall not require transmission service and Transmission Customers shall not reserve transmission service for such Up-to Congestion Transactions. Market Participants whose purchases and sales, and Transmission Customers whose transmission uses are scheduled in the Day-ahead Energy Market, shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, at the applicable Day-ahead Prices for the amounts scheduled.

(c) (i) In the Real-time Energy Market, Market Participants that deviate from the amounts of energy purchases or sales scheduled in the Day-ahead Energy Market shall be obligated to purchase or sell energy for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(ii) In the Real-time Energy Market, Transmission Customers that deviate from the transmission uses, scheduled in the Day-ahead Energy Market shall be obligated to pay Transmission Congestion Charges and Transmission Loss Charges for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(iii) Market Participants that deviate in real-time from the amounts of Secondary Reserve, Non-Synchronized Reserve, or Synchronized Reserve sales, scheduled day-ahead shall be obligated to purchase Secondary Reserve, Non-Synchronized Reserve, or Synchronized Reserve for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly

energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling does not encompass Coordinated External Transactions, which are subject to the procedures of Operating Agreement, Schedule 1, section 1.13. Scheduling shall be conducted as specified in section 1.10.1A below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM Manuals. Such resources committed by the Office of the Interconnection to alleviate or mitigate an Emergency will not receive ~~Operating Reserve~~energy uplift Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Operating Agreement, Schedule 1, section 3.2.3 and Operating Agreement, Schedule 1, section 6.6.

(e) To the extent that Tariff, Attachment K-Appendix, sections 3.2.3A, 3.2.3A.001, and 3.2.3A.01 and the parallel provision of Operating Agreement, Schedule 1, sections 3.2.3A, 3.2.3A.001, and 3.2.3A.01 does not meet the Minimum Synchronized Reserve Requirement, the Minimum Primary Reserve Requirement, and the Minimum 30-minute Reserve Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Tariff, Attachment K-Appendix, section 1.7.17 and the parallel provision of Operating Agreement, Schedule 1, section 1.7.17, and Tariff, Attachment K-Appendix, section 1.10 and the parallel provision of Operating Agreement, Schedule 1, section 1.10. In addition, the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the day-ahead market.

1.10.1A Day-ahead and Real-time Energy Market Scheduling.

The following actions shall occur not later than 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the Office of the Interconnection in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Schedule.

(a) Each Market Participant may submit to the Office of the Interconnection specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the PJM Manuals. Each Market Buyer shall inform the Office of the Interconnection of the prices, if any, at which it desires not to include its load in the Day-ahead Energy Market rather than pay the Day-ahead Price. PRD Providers that have committed Price Responsive Demand in accordance with the Reliability Assurance Agreement shall submit to the Office of the Interconnection, in accordance with procedures specified in the PJM Manuals, any desired updates to their previously submitted PRD Curves, provided that such updates are consistent with their Price Responsive Demand commitments, and provided further that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue

may only submit PRD Curves for the Real-time Energy Market. Price Responsive Demand that has been committed in accordance with the Reliability Assurance Agreement shall be presumed available for the next Operating Day in accordance with the most recently submitted PRD Curve unless the PRD Curve is updated to indicate otherwise. PRD Providers may also submit PRD Curves for any Price Responsive Demand that is not committed in accordance with the Reliability Assurance Agreement; provided that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue may only submit PRD Curves for the Real-time Energy Market. All PRD Curves shall be on a PRD Substation basis, and shall specify the maximum time period required to implement load reductions.

(b) Each Generating Market Buyer shall submit to the Office of the Interconnection: (i) hourly schedules for resource increments, including hydropower units, self-scheduled by the Market Buyer to meet its Equivalent Load; and (ii) the Dispatch Rate at which each such self-scheduled resource will disconnect or reduce output, or confirmation of the Market Buyer's intent not to reduce output.

(c) All Market Participants shall submit to the Office of the Interconnection schedules for any energy exports, energy imports, and wheel through transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection if the transaction is to be scheduled in the Day-ahead Energy Market. Any Market Participant that elects to schedule an export, import or wheel through transaction in the Day-ahead Energy Market may specify the price (such price not to exceed $2,000/MWh), if any, at which the export, import or wheel through transaction will be wholly or partially curtailed. The foregoing price specification shall apply to the applicable interface pricing point. Any Market Participant that elects not to schedule its export, import or wheel through transaction in the Day-ahead Energy Market shall inform the Office of the Interconnection if the parties to the transaction are not willing to incur Transmission Congestion and Loss Charges in the Real-time Energy Market in order to complete any such scheduled transaction. Such transactions in the Real-time Energy Market, other than Coordinated Transaction Schedules and emergency energy sales and purchases, may specify a price up to $2,000/MWh. Scheduling of such transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

i) Market Participants shall submit schedules for all energy purchases for delivery within the PJM Region, whether from resources inside or outside the PJM Region;

ii) Market Participants shall submit schedules for exports for delivery outside the PJM Region from resources within the PJM Region that are not Dynamic Transfers to such entities pursuant to Operating Agreement, Schedule 1, section 1.12; and

iii) In addition to the foregoing schedules for exports, imports and wheel through transactions, Market Participants shall submit confirmations of each scheduled transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(c-1) A Market Participant may elect to submit in the Day-ahead Energy Market a form of Virtual Transaction that combines an offer to sell energy at a source, with a bid to buy the same megawatt quantity of energy at a sink where such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink. The Office of Interconnection will schedule these transactions only to the extent this difference in Locational Marginal Prices is within the maximum amount specified by the Market Participant. A Virtual Transaction of this type is referred to as an "Up-to Congestion Transaction." Such Up-to Congestion Transactions may be wholly or partially scheduled depending on the price difference between the source and sink locations in the Day-ahead Energy Market. The maximum difference between the source and sink prices that a participant may specify shall be limited to +/- $50/MWh. The foregoing price specification shall apply to the price difference between the specified source and sink in the day-ahead scheduling process only. An accepted Up-to Congestion Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-ahead Energy Market.

(c–2) A Market Participant may elect to submit an Increment Offer and/or Decrement Bid form of Virtual Transaction in the Day-ahead Energy Market and shall specify the price for such transaction which shall be limited to $2,000/megawatt-hour.

(c-3) Up-to Congestion Transactions may only be submitted at hubs, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b). Increment Offers and Decrement Bids may be only submitted at hubs, nodes at which physical generation or load is settled, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b).

(d) Market Sellers in the Day-ahead Energy Market shall submit offers for the supply of energy, demand reductions, or other services for the following Operating Day for each clock hour for which the Market Seller desires or is required to make its resource available to the Office of the Interconnection. Offers for the supply of energy may be cost-based, market-based, or both, and may vary hourly. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, Operating Agreement, Schedule 2, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that is committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. Such offers shall be based on the ICAP equivalent of the Market Seller's cleared UCAP capacity commitment, provided, however, (i) where the underlying resource is a Capacity Storage Resource, with the exception of Capacity Storage Resource participating in the Energy Storage Resource Participation Model, or an Intermittent Resource, the Market Seller shall satisfy the must offer requirement by either self-scheduling or offering the unit as a dispatchable resource, in accordance with the PJM Manuals, where the hourly day-ahead self-scheduled values for such Capacity Storage Resources and Intermittent Resources may vary hour to hour

from the capacity commitment, and (ii) where the underlying resource is a Hybrid Resource or Capacity Storage Resource participating in the Energy Storage Resource Participation Model, the Market Seller shall satisfy the must offer requirement by self-scheduling the unit in accordance with the PJM Manuals, where the hourly day-ahead self-scheduled values for such Hybrid Resource or Capacity Storage Resource may vary hour to hour from the capacity commitment. Any offer not designated as a Maximum Emergency offer shall be considered available for scheduling and dispatch under both Emergency and non-Emergency conditions. Offers may only be designated as Maximum Emergency offers to the extent that the Generation Capacity Resource falls into at least one of the following categories:

i) Environmental limits. If the resource has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited to operating only during declared PJM capacity emergencies by a governmental authority.

ii) Fuel limits. If physical events beyond the control of the resource owner result in the temporary interruption of fuel supply and there is limited on-site fuel storage. A fuel supplier's exercise of a contractual right to interrupt supply or delivery under an interruptible service agreement shall not qualify as an event beyond the control of the resource owner.

iii) Temporary emergency conditions at the unit. If temporary emergency physical conditions at the resource significantly limit its availability.

iv) Temporary megawatt additions. If a resource can provide additional megawatts on a temporary basis by oil topping, boiler over-pressure, or similar techniques, and such megawatts are not ordinarily otherwise available.

The submission of offers for resource increments that are not committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1 shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2, and the PJM Manuals, as applicable. Energy offered from generation resources that are not committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1 shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region.

The foregoing offers:

i) Shall specify the Generation Capacity Resource or Economic Load Response Participant resource and energy or demand reduction amount, respectively, for each clock hour in the offer period;

ii) Shall specify the amounts and prices for each clock hour during the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;

iii) May specify for generation resources offer parameters for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) Minimum Run Time; (2) maximum run time; (3) Start-up Costs; (4) No-load Costs; (5) Incremental Energy Offer; (6) notification time; (7) availability; (8) ramp rate; (9) Economic Minimum; (10) Economic Maximum; (11) emergency minimum MW; (12) emergency maximum MW; (13) Synchronized Reserve maximum MW; (14) Secondary Reserve maximum MW; and (15) condense to generation time constraints, and may specify offer parameters for Economic Load Response Participant resources for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) minimum down time; (2) maximum down time; (3) minimum release time; (4) shutdown costs; (5) Incremental Energy Offer; (6) notification time; (7) Economic Minimum; and (8) Economic Maximum;

iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;

v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with additional schedules applicable if accepted after the foregoing deadline;

vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer for the clock hour, which offer shall remain open through the Operating Day, for which the offer is submitted, unless the Market Seller a) submits a Real-time Offer for the applicable clock hour, or b) updates the availability of its offer for that hour, as further described in the PJM Manuals;

vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day, unless modified after the close of the Day-ahead Energy Market as permitted pursuant to sections 1.10.9A or 1.10.9B below;

viii) Shall not exceed an energy offer price of $1,000/megawatt-hour for all generation resources, except (1) when a Market Seller's cost-based offer is

above $1,000/megawatt-hour and less than or equal to $2,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer; and (2) when a Market Seller's cost-based offer is greater than $2,000/megawatt-hour, then its market-based offer must be less than or equal to $2,000/megawatt-hour;

ix) Shall not exceed a demand reduction offer price of $1,000/megawatt-hour, except when an Economic Load Response Participant submits a cost-based offer that includes an incremental cost component that is above $1,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer but in no event greater than $2,000/megawatt-hour;

x) Shall not exceed an offer price as follows for Emergency Load Response and Pre-Emergency Load Response participants with:

a) a 30 minute lead time, pursuant to Tariff, Attachment DD-1, section A.2 and the parallel provision of RAA, Schedule 6, $1,000/megawatt-hour, plus the applicable Reserve Penalty Factor for the Primary Reserve Requirement, minus $1.00;

b) an approved 60 minute lead time, pursuant to Tariff, Attachment DD-1, section A.2 and the parallel provision of RAA, Schedule 6, $1,000/megawatt-hour, plus [the applicable Reserve Penalty Factor for the Primary Reserve Requirement divided by 2]; and

c) an approved 120 minute lead time, pursuant to Tariff, Attachment DD-1, section A.2 and the parallel provisions of RAA, Schedule 6, $1,100/megawatt-hour; and

xi) Shall not exceed an energy offer price of $0.00/MWh for pumped storage hydropower units scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation for each 30 minute Regulation clearing interval for which the Market Seller desires to make its resource available to the Office of the Interconnection to provide Regulation that shall specify the megawatts of Regulation being offered, which must equal or exceed 0.1 megawatts, in the Regulation Zone for which such Regulation is offered, the price of the capability offer in dollars per MW, the price of the mileage offer in Dollars per change in MW, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the resource's opportunity costs. Such offers may vary for each 30 minute Regulation clearing interval, and may be updated each 30 minute Regulation clearing interval, up to 35 minutes before the applicable 30 minute Regulation clearing interval during the Operating Day. The total of the mileage offer multiplied by the historical average mileage used in the market clearing plus the capability offer shall not exceed $100/megawatt-

hour. In addition to any market-based offer for Regulation, the Market Seller also shall submit a cost-based offer. A cost-based offer must be in the form specified in the PJM Manuals and consist of the following components as well as any other components specified in the PJM Manuals:

i. The costs (in $/MW) of the fuel cost increase due to the steady-state heat rate increase resulting from operating the unit at lower megawatt output incurred from the provision of Regulation shall apply to the capability offer;

ii. The cost increase (in $/ΔMW) in costs associated with movement of the regulation resource incurred from the provision of Regulation shall apply to the mileage offer; and

a. Only Regulation-only resources may include all variable operation and maintenance expenses in the mileage offer, as defined in the PJM Manuals.

iii. An adder of up to $12.00 per megawatt of Regulation provided applied to the capability offer.

Qualified Regulation capability must satisfy the measurement and verification tests specified in the PJM Manuals.

(f) Each Market Seller owning or controlling the output of a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative shall submit a forecast of the availability of each such Generation Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with Start-up Costs and No-load Costs, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours. Such resources committed by the Office of the Interconnection will not receive ~~Operating Reserve~~ energy uplift Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Operating Agreement, Schedule 1, section 3.2.3 and Operating Agreement, Schedule 1, section 6.6.

(g) Each component of an offer by a Market Seller of a Generation Capacity Resource that is constant for the entire Operating Day and does not vary hour to hour shall remain in effect for subsequent Operating Days until superseded or canceled.

(h) The Office of the Interconnection shall post the total hourly loads scheduled in the Day-ahead Energy Market, as well as, its estimate of the combined hourly load of the Market Buyers for the next four days, and peak load forecasts for an additional three days.

(i) Except for Economic Load Response Participants, all Market Participants may submit Virtual Transactions that apply to the Day-ahead Energy Market only. Such Virtual Transactions must comply with the requirements set forth in the PJM Manuals and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-ahead Energy Market. The Office of the Interconnection may require that a market participant shall not submit in excess of a defined number of bid/offer segments in the Day-ahead Energy Market, as specified in the PJM Manuals, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to 10:00 a.m. EPT on the day that the Day-ahead Energy Market will clear. For purposes of this provision, a bid/offer segment is each pairing of price and megawatt quantity submitted as part of an Increment Offer or Decrement Bid. For purposes of applying this provision to an Up-to Congestion Transaction, a bid/offer segment shall refer to the pairing of a source and sink designation, as well as price and megawatt quantity, that comprise each Up-to Congestion Transaction.

(j) (i) Offers to Supply Synchronized and Non-Synchronized Reserves By Generation Resources in the Day-ahead and Real-time Reserve Markets

(1) Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Tariff, Attachment DD, is capable of providing Synchronized Reserve or Non-Synchronized Reserve as specified in section 1.7.19A(a), in section 1.7.19A.01(a) and in the PJM Manuals, and has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage, shall submit offers or otherwise make their 10-minute reserve capability available to supply Synchronized Reserve or, as applicable, Non-Synchronized Reserve, including any portion that is self-scheduled by the Generating Market Buyer, in an amount equal to the available 10-minute reserve capability of such Generation Capacity Resource. Market Sellers of Generation Capacity Resources subject to this must-offer requirement that do not make the reserve capability of such resources available when such resource is able to operate with a dispatchable range (e.g. through offering a fixed output) will be in violation of this provision.

(2) Market Sellers of all other generation resources that (A) are capable of providing Synchronized Reserve or Non-Synchronized Reserve, as specified in section 1.7.19A(a), in section 1.7.19A.01(a) and in the PJM Manuals, (B) are located within the metered boundaries of the PJM Region, and (C) have submitted offers for the supply of energy into the Day-ahead Energy Market and/or Real-time Energy Market shall be deemed to have made their reserve capability available to provide Synchronized Reserve or Non-Synchronized Reserve in the Day-ahead Energy Market and/or Real-time Energy Market for each clock hour for which the Market Seller submits an available offer to supply energy; provided,

however that hydroelectric generation resources and Energy Storage Resources are not automatically deemed available to provide reserves based on the submission of an available energy offer but may submit offers to supply Synchronized Reserve and Non-Synchronized Reserve, as applicable.

(3) Offers for the supply of Synchronized Reserve by all generation resources must be cost-based. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A, section 1.10.9B below, and the PJM Manuals, as applicable. For offers to supply Synchronized Reserve, the offer price shall not exceed the expected value of the penalty for failing to provide Synchronized Reserve, where such expected value shall be recalculated annually, in accordance with the PJM Manuals, and posted on PJM's website. The expected value of the penalty is calculated as the product of: (A) the average penalty, expressed in $/MWh, multiplied by (B) the average rate of non-performance during Synchronized Reserve events multiplied by (C) the probability a Synchronized Reserve event that will qualify for non-performance assessments will occur.

The expected value of the penalty shall be determined by an annual review of the twelve-month period ending October 31 of the calendar year in which the review is performed. The Office of the Interconnection shall post the results of its annual review by no later than December 15, and the revised offer price cap shall be effective as of the following January 1; provided, however, that at the time of implementation of this rule the expected value of the penalty shall be $0.02/MWh, and for the period from the second month after implementation through the second December 31 following such date of implementation, the expected value of the penalty shall be recalculated on a monthly basis using data from the implementation date of this rule through the 15th day of the current month, and the revised value shall be effective the 1st day of the following month.

(4) All Non-Synchronized Reserve offers shall be for $0.00/MWh. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this subsection (d) of this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

(ii) Determination of Available Synchronized Reserve Capability of Generation Resources

(1) For each offer to supply reserves by a synchronized resource, the Office of the Interconnection shall determine the MW of available Synchronized Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market, in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Hydroelectric generation resources and Energy Storage Resources may submit offers for their available Synchronized Reserve capability as part of their offer into the Synchronized Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(j)(i) above must submit a Synchronized Reserve offer which specifies the MW of available Synchronized Reserve capability in order to remain compliant with such requirements.

(2) An on-line generation resource's available Synchronized Reserve capability, except for generation resources capable of synchronous condensing, shall be determined in accordance with the PJM Manuals and based on the resource's current performance and initial energy output and the following offer parameters submitted as part of the resource's energy offer: (A) ramp rate; (B) Economic Minimum; and (C) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Synchronized Reserves above the Synchronized Reserve maximum MW.

For generation resources capable of synchronous condensing, the resource's available Synchronized Reserve capability shall be based on the following offer parameters submitted as part of the resource's energy offer: (D) ramp rate; (E) condense to generation time constraints; (F) Economic Minimum; and (G) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Synchronized Reserves above the Synchronized Reserve maximum MW.

(3) Any Market Seller that believes its generating unit has operating modes, limits, or conditions where the unit would not be capable of providing Synchronized Reserves in real time, can submit to the Office of the Interconnection with a copy to the Market Monitoring Unit a request for an exception from being assigned Synchronized Reserves in the Real-time Synchronized Reserve Market during time periods in which the generating unit is in those operating modes, limits, or conditions. As part of the request, the Market

Seller shall supply, for each generating unit, technical information about the operational modes, limits, or conditions to support the requested exception, as further detailed in the PJM Manuals. The Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a request for such an exception. Within 60 days of the submission of the request, the Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, whether the request is approved or denied. The effective date of any approved request will be provided in the written notification. If a Market Seller has an approved exception, the Market Seller must communicate to the Office of the Interconnection when the unit cannot provides reserves, and the Office of the Interconnection will provide a mechanism for Market Sellers with an approved exception to provide such communication to the Office of the Interconnection in real time, as further detailed in the PJM Manuals. An approved exception will remain applicable to the unit until such time as the Office of the Interconnection determines that a change is needed or the Market Seller notifies the Office of the Interconnection, with a copy to the Market Monitoring Unit, that a change is needed based on changed operational capabilities of the unit. Market Sellers must notify the Office of the Interconnection, with a copy to the Market Monitoring Unit, within 30 days of any changed operational capabilities that necessitate a change in an approved exception.

(iii) Determination of Available Non-Synchronized Reserve Capability of Generation Resources

(1) For each offer to supply reserves by an off-line generation resource, the Office of the Interconnection shall determine the MW of available Non-Synchronized Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Such hydroelectric generation resources or Energy Storage Resources may submit offers for their available Non-Synchronized Reserve capability as part of their offer into the Non-Synchronized Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(j)(i) above must submit a Non-Synchronized Reserve offer which specifies the MW of available Non-Synchronized Reserve capability in order to remain compliant with such requirements.

(2) An off-line generation resource's available Non-Synchronized Reserve capability shall be determined in accordance with the PJM Manuals and based on the following offer parameters submitted as part of the resource's energy offer: (A) startup time; (B) notification time; (C) ramp rate; (D) Economic Minimum; and (E) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the

Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Non-Synchronized Reserves above its Synchronized Reserve maximum MW.

(iv) Offers to Supply Synchronized Reserves by Economic Load Response Participant Resources in the Day-ahead and Real-time Reserve Markets

(1) Economic Load Response Participants that submit offers to reduce demand into the Day-ahead Energy Market and Real-time Energy Market and wish to make their resources available to supply Synchronized Reserve may submit offers to supply Synchronized Reserve from such resources, where such offers shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.1 megawatts and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day.

(2) All offers to supply Synchronized Reserve offers from Economic Load Response Participant resources shall not exceed the expected value of the penalty for failing to provide Synchronized Reserve, as determined in accordance with section 1.10.1A(j)(i)(3) above. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

(k) An Economic Load Response Participant that wishes to participate in the Day-ahead Energy Market by reducing demand shall submit an offer to reduce demand to the Office of the Interconnection for each clock hour for which the Economic Load Response Participant desires to make its resource available to the Office of the Interconnection to reduce demand. The offer must equal or exceed 0.1 megawatts, may vary hourly, and shall specify: (i) the amount of the offered curtailment in minimum increments of .1 megawatts: (ii) the Day-ahead Locational Marginal Price above which the end-use customer will reduce load, subject to section 1.10.1A(d)(ix); and (iii) at the Economic Load Response Participant's option, shutdown costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum of number of contiguous hours for which the load reduction must be committed. Such offers may be updated each hour, up to 65 minutes before the applicable clock hour during the Operating Day. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs) per hour.

(l) Market Sellers owning or controlling the output of an Economic Load Response Participant resource that was committed in an FRR Capacity Plan, or that was self-supplied or that offered and cleared in a Base Residual Auction or Incremental Auction, may submit demand

reduction bids for the available load reduction capability of the Economic Load Response Participant resource. The submission of demand reduction bids for Economic Load Response Participant resource increments that were not committed in an FRR Capacity Plan, or that have not cleared in a Base Residual Auction or Incremental Auction, shall be optional, but any such bids must contain the information required to be included in such bids, as specified in the PJM Economic Load Response Program. An Economic Load Response Participant resource that was committed in an FRR Capacity Plan, or that was self-supplied or offered and cleared in a Base Residual Auction or Incremental Auction, may submit a demand reduction bid in the Day-ahead Energy Market as specified in the Economic Load Response Program; provided, however, that in the event of an Emergency PJM shall require Economic Load Response Participant resources to reduce load, notwithstanding that the Zonal LMP at the time such Emergency is declared is below the price identified in the demand reduction bid.

(m) (i) Offers to Supply Secondary Reserve By Generation Resources

(1) Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Tariff, Attachment DD, that is available for energy, is capable of providing Secondary Reserve, as specified in section 1.7.19A.02(a) and in the PJM Manuals, and has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers to supply Secondary Reserve, or otherwise make their Secondary Reserve capability available. Such offers shall be for an amount equal to the resource's available energy output achievable within thirty minutes (less its energy output achievable within ten minutes) from a request of the Office of the Interconnection. Market Sellers of Generation Capacity Resources subject to this must-offer requirement that do not make the reserve capability of such resources available when such resource is able to operate with a dispatchable range (e.g. through offering a fixed output) will be in violation of this provision.

(2) Market Sellers of all other generation resources located within the metered boundaries of the PJM Region that submit offers for the supply of energy into the Day-ahead Energy Market and/or Real-time Energy Market and are capable of providing Secondary Reserve, as specified in the PJM Manuals, shall be deemed to have made their reserve capability available to provide Secondary Reserve in the Day-ahead Energy Market and/or Real-time Energy Market for each clock hour for which the Market Seller submits an available offer to supply energy; provided, however that hydroelectric generation resources and Energy Storage Resources are not automatically deemed available to provide reserves based on the submission of an available energy offer but may submit offers to supply Secondary Reserve, as applicable.

(3) Offers for the supply of Secondary Reserve shall be for $0.00/MWh. Consistent with the resource's offer to supply energy, such offers may vary hourly

and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this subsection (d) above, section 1.10.9B below, and the PJM Manuals, as applicable.

(ii) Determination of Available Secondary Reserve Capability of Generation Resources

(1) For each offer to supply Secondary Reserve by a generation resource, the Office of the Interconnection shall determine the MW of available Secondary Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Hydroelectric generation resources or Energy Storage Resources may submit their available Secondary Reserve capability as part of their offer into the Secondary Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(m)(i) above must submit a Secondary Reserve offer which specifies the MW of available Secondary Reserve capability in order to remain compliant with such requirements.

(2) (A) An on-line generation resource's available Secondary Reserve capability, except for generation resources capable of synchronous condensing, shall be based on the resource's current performance and initial energy output, the resource's available Synchronized Reserve capability; and the following offer parameters submitted as part of the energy offer: (i) ramp rate; (ii) Economic Minimum; and (iii) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(B) For generation resources capable of synchronous condensing, the resource's available Secondary Reserve capability shall be based on the following offer parameters submitted as part of the energy offer: (i) ramp rate; (ii) condense to generation time constraints; (iii) Economic Minimum; and (iv) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that

the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(C) An off-line generation resource's available Secondary Reserve capability, shall be based on the resource's available Secondary Reserve capability and the following offer parameters submitted as part of the resource's energy offer: (i) startup time; (ii) notification time; (iii) ramp rate; (iv) Economic Minimum; and (v) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(3) Any Market Seller that believes its generating unit has operating modes, limits, or conditions where the unit would not be capable of providing Secondary Reserves in real time, can submit to the Office of the Interconnection with a copy to the Market Monitoring Unit a request for an exception from being assigned Secondary Reserves in the Real-time Secondary Reserve Market during time periods in which the generating unit is in those operating modes, limits, or conditions. As part of the request, the Market Seller shall supply, for each generating unit, technical information about the operational modes, limits, or conditions to support the requested exception, as further detailed in the PJM Manuals. The Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a request for such an exception. Within 60 days of the submission of the request, the Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, whether the request is approved or denied. The effective date of any approved request will be provided in the written notification. If a Market Seller has an approved exception, the Market Seller must communicate to the Office of the Interconnection when the unit cannot provides reserves, and the Office of the Interconnection will provide a mechanism for Market Sellers with an approved exception to provide such communication to the Office of the Interconnection in real time, as further detailed in the PJM Manuals. An approved exception will remain applicable to the unit until such time as the Office of the Interconnection determines that a change is needed or the Market Seller notifies the Office of the Interconnection, with a copy to the Market Monitoring Unit, that a change is needed based on changed operational capabilities of the unit. Market Sellers must notify the Office of the Interconnection, with a copy to the Market Monitoring

Unit, within 30 days of any changed operational capabilities that necessitate a change in an approved exception.

(iii) Offers to Supply Secondary Reserves by Economic Load Response Participant resources

(1) Each Economic Load Response Participant that submits offers to reduce demand into the Day-ahead Energy Market and Real-time Energy Market and wishes to make their resources available to supply Secondary Reserve shall submit offers to supply Secondary Reserve from such resources, where such offers shall specify the megawatts of Secondary Reserve being offered, which must equal or exceed 0.1 megawatts and include such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day.

(2) All Secondary Reserve offers by Economic Load Response Participant resources shall be for $0.00/MWh. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

(n) A Market Participant may submit a Day-Ahead Pseudo-Tie Transaction for a Market Participant's generator within the PJM balancing authority area that is a Pseudo-Tie into the MISO balancing authority area. Day-Ahead Pseudo-Tie Transactions combine an offer to sell energy at a source with a bid to buy the same megawatt quantity of energy at a sink where such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink.

Each Day-Ahead Pseudo-Tie Transaction shall: (1) source at a Market Participant's generator within the PJM balancing authority area that Pseudo-Ties into MISO; and (2) sink at the PJM-MISO interface. A Market Participant must reserve transmission service in accordance with the PJM Tariff for each Day-Ahead Pseudo-Tie Transaction. Megawatt quantities for Day-Ahead Pseudo-Tie Transactions shall be greater than zero and less than or equal to the transmission service reserved for the Day-Ahead Pseudo-Tie Transaction. An accepted Day-Ahead Pseudo-Tie Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-Ahead Energy Market.

1.10.1B Demand Bid Scheduling and Screening

(a) The Office of the Interconnection shall apply Demand Bid Screening to all Demand Bids submitted in the Day-ahead Energy Market for each Load Serving Entity, separately by Zone. Using Demand Bid Screening, the Office of the Interconnection will automatically reject a Load Serving Entity's Demand Bids in any future Operating Day for which the Load Serving Entity

submits bids if the total megawatt volume of such bids would exceed the Load Serving Entity's Demand Bid Limit for any hour in such Operating Day, unless the Office of the Interconnection permits an exception pursuant to subsection (d) below.

(b) On a daily basis, PJM will update and post each Load Serving Entity's Demand Bid Limit in each applicable Zone. Such Demand Bid Limit will apply to all Demand Bids submitted by that Load Serving Entity for each future Operating Day for which it submits bids. The Demand Bid Limit is calculated using the following equation:

Demand Bid Limit = greater of (Zonal Peak Demand Reference Point * 1.3), or (Zonal Peak Demand Reference Point + 10MW)

Where:

1. Zonal Peak Demand Reference Point = for each Zone: the product of (a) LSE Recent Load Share, multiplied by (b) Peak Daily Load Forecast.
2. LSE Recent Load Share is the Load Serving Entity's highest share of Network Load in each Zone for any hour over the most recently available seven Operating Days for which PJM has data.
3. Peak Daily Load Forecast is PJM's highest available peak load forecast for each applicable Zone that is calculated on a daily basis.

(c) A Load Serving Entity whose Demand Bids are rejected as a result of Demand Bid Screening may change its Demand Bids to reduce its total megawatt volume to a level that does not exceed its Demand Bid Limit, and may resubmit them subject to the applicable rules related to bid submission outlined in Tariff, Operating Agreement and PJM Manuals.

(d) PJM may allow a Load Serving Entity to submit bids in excess of its Demand Bid Limit when circumstances exist that will cause, or are reasonably expected to cause, a Load Serving Entity's actual load to exceed its Demand Bid Limit on a given Operating Day. Examples of such circumstances include, but are not limited to, changes in load commitments due to state sponsored auctions, mergers and acquisitions between PJM Members, and sales and divestitures between PJM Members. A Load Serving Entity may submit a written exception request to the Office of Interconnection for a higher Demand Bid Limit for an affected Operating Day. Such request must include a detailed explanation of the circumstances at issue and supporting documentation that justify the Load Serving Entity's expectation that its actual load will exceed its Demand Bid Limit.

1.10.2 Pool-scheduled Resources.

Pool-scheduled resources are those resources for which Market Participants submitted offers to sell energy in the Day-ahead Energy Market and offers to reduce demand in the Day-ahead Energy Market, which the Office of the Interconnection scheduled in the Day-ahead Energy Market as well as generators committed by the Office of the Interconnection subsequent to the Day-ahead Energy Market. Such resources shall be committed to provide energy in the real-time dispatch unless the schedules for such units are revised pursuant to section 1.10.9 below or

Operating Agreement, Schedule 1, section 1.11. Pool-scheduled resources shall be governed by the following principles and procedures.

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, whether the resource is expected to be needed to maintain system reliability during the Operating Day, Start-up Costs, No-load Costs, and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in section 1.10.1A above. Hydropower units can only be pool-scheduled if they are pumped storage units and scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

(b) A resource that is scheduled by a Market Participant to support a bilateral sale, or that is self-scheduled by a Generating Market Buyer, shall not be selected by the Office of the Interconnection as a pool-scheduled resource except in an Emergency.

(c) Market Sellers offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the Office of the Interconnection that is sufficient to enable the Office of the Interconnection to determine the available operating hours of such facilities.

(d) The Market Seller of a resource selected as a pool-scheduled resource shall receive payments or credits for energy, demand reductions or related services, or for Start-up Costs and No-load Costs, from the Office of the Interconnection on behalf of the Market Buyers in accordance with Operating Agreement, Schedule 1, section 3. Alternatively, the Market Seller shall receive, in lieu of Start-up Costs and No-load Costs, its actual costs incurred, if any, up to a cap of the resource's Start-up Costs, if the Office of the Interconnection cancels its selection of the resource as a pool-scheduled resource and so notifies the Market Seller before the resource is synchronized.

(e) Market Participants shall make available their pool-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone.

(f) Economic Load Response Participants offering to reduce demand shall specify: (i) the amount of the offered curtailment, which must equal or exceed 0.1 megawatts, in minimum increments of 0.1 megawatts; (ii) the real-time Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, shut-down costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum number of contiguous hours for which the load reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market and/or the Real-time Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs). Economic Load Response Participants offering to reduce demand shall also indicate the hours that the demand reduction is not available.

1.10.3 Self-scheduled Resources.

Self-scheduled resources shall be governed by the following principles and procedures.

(a) Each Generating Market Buyer shall use all reasonable efforts, consistent with Good Utility Practice, not to self-schedule resources in excess of its Equivalent Load.

(b) The offered prices of resources that are self-scheduled and not dispatchable by the Office of the Interconnection shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.

(c) Market Participants shall make available their self-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone, by submitting an offer as to such resources.

(d) A Market Participant self-scheduling a resource in the Day-ahead Energy Market that does not deliver the energy in the Real-time Energy Market, shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(e) A Market Participant self-scheduling a resource to supply Synchronized Reserve in the Day-ahead Synchronized Reserve Market that does not deliver the scheduled megawatt quantity in the applicable real-time reserve market, shall replace the Synchronized Reserve not delivered and shall pay for such Synchronized Reserve at the applicable Real-time Synchronized Reserve Market Clearing Price. Market Participants shall not self-schedule a resource to provide Secondary Reserve or Non-Synchronized Reserve.

(f) For energy, hydropower units, excluding pumped storage units, may only be self-scheduled.

(g) A resource that has been self-scheduled shall not receive payments or credits for Start-up Costs or No-load Costs.

1.10.4 Capacity Resources.

(a) A Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that is selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection. Such a Generation Capacity Resource that does not deliver energy as scheduled shall be deemed to have experienced a Generator Forced Outage to the extent of such energy not delivered. A Market Participant offering such Generation Capacity Resource in the Day-ahead Energy Market shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Energy from a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that has not been scheduled in the Day-ahead Energy Market may be sold on a bilateral basis by the Market Seller, may be self-scheduled, or may be offered for dispatch during the Operating Day in accordance with the procedures specified in this Schedule. Such a Generation Capacity Resource that has not been scheduled in the Day-ahead Energy Market and that has been sold on a bilateral basis must be made available upon request to the Office of the Interconnection for scheduling and dispatch during the Operating Day if the Office of the Interconnection declares a Maximum Generation Emergency. Any such resource so scheduled and dispatched shall receive the applicable Real-time Price for energy delivered.

1.10.5 External Resources.

(a) External Resources may submit offers to the PJM Interchange Energy Market, in accordance with the day-ahead and real-time scheduling processes specified above. An External Resource selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection, and except as specified below shall be compensated on the same basis as other pool-scheduled resources. External Resources that are not capable of Dynamic Transfer shall, if selected by the Office of the Interconnection on the basis of the Market Seller's Offer Data, be block loaded on an hourly scheduled basis. Market Sellers shall offer External Resources to the PJM Interchange Energy Market on either a resource-specific or an aggregated resource basis. A Market Participant whose pool-scheduled resource does not deliver the energy scheduled in the Day-ahead Energy Market shall replace such energy not delivered as scheduled in the Day-ahead Energy Market with energy from the PJM Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Offers for External Resources from an aggregation of two or more generating units shall so indicate, and shall specify, in accordance with the Offer Data requirements specified by the Office of the Interconnection: (i) energy prices; (ii) hours of energy availability; (iii) a minimum dispatch level; (iv) a maximum dispatch level; and (v) unless such information has previously been made available to the Office of the Interconnection, sufficient information, as specified in the PJM Manuals, to enable the Office of the Interconnection to model the flow into the PJM Region of any energy from the External Resources scheduled in accordance with the Offer Data.

(c) Offers for External Resources on a resource-specific basis shall specify the resource being offered, along with the information specified in the Offer Data as applicable.

1.10.6 External Market Buyers.

(a) Deliveries to an External Market Buyer not subject to Dynamic Transfer by the Office of the Interconnection shall be delivered on a block loaded basis to the bus or buses at the electrical boundaries of the PJM Region, or in such area with respect to an External Market Buyer's load within such area not served by Network Service, at which the energy is delivered to or for the External Market Buyer. External Market Buyers shall be charged (which charge may be positive

or negative) at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing bus or buses.

(b) An External Market Buyer's hourly schedules for energy purchased from the PJM Interchange Energy Market shall conform to the ramping and other applicable requirements of the interconnection agreement between the PJM Region and the Control Area to which, whether as an intermediate or final point of delivery, the purchased energy will initially be delivered.

(c) The Office of the Interconnection shall curtail deliveries to an External Market Buyer if necessary to maintain appropriate reserve levels for a Control Zone as defined in the PJM Manuals, or to avoid shedding load in such Control Zone.

1.10.7 Bilateral Transactions.

Bilateral transactions as to which the parties have notified the Office of the Interconnection by the deadline specified in section 1.10.1A above that they elect not to be included in the Day-ahead Energy Market and that they are not willing to incur Transmission Congestion Charges in the Real-time Energy Market shall be curtailed by the Office of the Interconnection as necessary to reduce or alleviate transmission congestion. Bilateral transactions that were not included in the Day-ahead Energy Market and that are willing to incur congestion charges and bilateral transactions that were accepted in the Day-ahead Energy Market shall continue to be implemented during periods of congestion, except as may be necessary to respond to Emergencies.

1.10.8 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers and PRD Curves properly submitted by PRD Providers; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv) the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated flowgates to the extent provided by Operating Agreement, Schedule 1, section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy

Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) By 1:30 p.m., or as soon as practicable thereafter, of the day before each Operating Day, or such other deadline as may be specified by the Office of the Interconnection in the PJM Manuals, the Office of the Interconnection shall: (i) post the aggregate Day-ahead Energy Market results; (ii) post the Day-ahead Prices; and (iii) inform the Market Sellers, Market Buyers, and Economic Load Response Participants of their scheduled injections, withdrawals, and demand reductions respectively. The foregoing notwithstanding, the deadlines set forth in this subsection shall not apply if the Office of the Interconnection is unable to obtain Market Participant bid/offer data due to extraordinary circumstances. For purposes of this subsection, extraordinary circumstances shall mean a technical malfunction that limits, prohibits or otherwise interferes with the ability of the Office of the Interconnection to obtain Market Participant bid/offer data prior to 11:59 p.m. on the day before the affected Operating Day. Extraordinary circumstances do not include a Market Participant's inability to submit bid/offer data to the Office of the Interconnection. If the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day as a result of such extraordinary circumstances, the Office of the Interconnection shall notify Members as soon as practicable.

(c) Following posting of the information specified in section 1.10.8(b), and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, the Office of the Interconnection shall revise its schedule of generation resources to reflect updated projections of load, conditions affecting electric system operations in the PJM Region, the availability of and constraints on limited energy and other resources, transmission constraints, and other relevant factors.

(d) Market Buyers shall pay PJMSettlement and Market Sellers shall be paid by PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is positive. Market Buyers shall be paid by PJMSettlement and Market Sellers shall pay PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Operating Agreement, Schedule 1, section 3.3A. Notwithstanding the foregoing, if the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day due to extraordinary circumstances as described in subsection (b) above, it will be declared a Market Suspension, and Day-ahead Prices shall be determined pursuant to Operating Agreement, Schedule 1, section 2.6.1. If the Office of the Interconnection declares a Market Suspension, it shall notify Market Participants of the Market Suspension as soon as practicable.

(e) If the Office of the Interconnection discovers a *potential* error in prices and/or cleared quantities in the Day-ahead Energy Market or Day-ahead Ancillary Services Markets, or the Real-time Energy Market or Real-time Ancillary Services Markets after it has posted the results

for these markets on its Web site, the Office of the Interconnection shall notify Market Participants as soon as possible after it is found, but in no event later than 12:00 p.m. of the second Business Day following the Operating Day for the Real-time Energy Market and Real-time Ancillary Services Markets, and no later than 5:00 p.m. of the second Business Day following the initial publication of the results for the Day-ahead Energy Market and Day-ahead Ancillary Services Markets. After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, *along with a description detailing the cause and scope of the error*, by no later than 5:00 p.m. of the fifth Business Day following the Operating Day for the Real-time Energy Market and Real-time Ancillary Services Markets, and no later than 5:00 p.m. of the fifth Business Day following the initial publication of the results in the Day-ahead Energy Market and Day-ahead Ancillary Services Markets. *The provided description will not contain information that is market sensitive or confidential.* Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating Day for the Day-ahead Energy Market, Real-time Energy Market, and Day-ahead Ancillary Services Markets, and Real-time Ancillary Service Markets. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced market results are under publicly noticed review by the FERC.

(f) Consistent with Operating Agreement, section 18.17.1, and notwithstanding anything to the contrary in the Operating Agreement or in the PJM Tariff, to allow the tracking of Market Participants' non-aggregated bids and offers over time as required by FERC Order No. 719, the Office of the Interconnection shall post on its Web site the non-aggregated bid data and Offer Data submitted by Market Participants (for participation in the PJM Interchange Energy Market) approximately four months after the bid or offer was submitted to the Office of the Interconnection.

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, a generation rebidding period shall exist. Typically the rebidding period shall be from the time the Office of the Interconnection posts the results of the Day-ahead Energy Market until 2:15 p.m. on the day before each Operating Day. However, should the clearing of the Day-ahead Energy Market be significantly delayed, the Office of the Interconnection may establish a revised rebidding period. During the rebidding period, Market Participants may submit revisions to generation Offer Data for the next Operating Day. Adjustments to the Day-ahead Energy Market shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 6:30 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 65 minutes prior to the hour in which the adjustment is to take effect, as follows and as specified in section 1.10.9A below:

i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;

ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or

iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or

iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any Start-Up Costs.

(c) An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase in the Day-ahead Energy Market by notifying the Office of the Interconnection of the adjustment in deliveries not later than 65 minutes prior to the hour in which the adjustment is to take effect, but any such adjustment shall not affect the obligation of the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(d) The Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules resulting from the rebidding period by 6:30 p.m. on the day before each Operating Day. The Office of the Interconnection may also commit additional resources after such time as system conditions require. For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this section 1.10, the Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules for the hour.

1.10.9A Updating Offers in Real-time

(a) Each Market Seller may submit Real-time Offers for a resource up to 65 minutes before the applicable clock hour, and such Real-time Offers shall supersede any previous offer for that resource for the clock hour, as further described in the PJM Manuals and subject to the following conditions:

(i) A market-based Real-time Offer shall not exceed the applicable energy offer caps specified in this Schedule. Once a Market Seller's resource is committed for an applicable clock hour, the Market Seller may not increase its Incremental Energy Offer and may only submit a market-based Real-time Offer that is higher than its market-based offer that was in effect at the time of commitment to reflect increases in the resource's cost-based Start-up Costs and cost-based No-load Costs. The Market Seller may elect not to have its market-based offer considered for dispatch and to have only its lowest cost-based offer considered for the remainder of the Operating Day.

(ii) Cost-based Real-time Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2 and the PJM Manuals, as applicable. If a Market Seller submits a market-based Real-time Offer for a particular clock hour in accordance with subsection (c) below, or if updates to a cost-based offer are required by the Market Seller's approved Fuel Cost Policy, the Market Seller shall update its previously submitted cost-based Real-time Offer.

(iii) If a Market Seller's available cost-based offer is not compliant with Operating Agreement, Schedule 2 and the PJM Manuals at the time a Market Seller submits a market-based Real-time Offer for an applicable clock hour during the Operating Day, the Market Seller must submit an updated cost-based Real-time Offer consisting of an Incremental Energy Offer, Start-up Cost, and No-load Cost for that clock hour that is compliant with Operating Agreement, Schedule 2 and the PJM Manuals.

(b) Each Market Seller may submit Real-time Offers for a resource during and through the end of the applicable clock hour to update only the following offer parameters, as further described in the PJM Manuals: (1) Economic Minimum; (2) Economic Maximum; (3) emergency minimum MW; (4) emergency maximum MW; (5) unit availability status; (6) fixed output indicator; (7) Synchronized Reserve maximum MW; and (8) Secondary Reserve maximum MW. Such Real-time Offers shall supersede any previous offer for that resource for the clock hour.

1.10.9B Offer Parameter Flexibility

(a) Market Sellers may, in accordance with sections 1.10.1A and 1.10.9A above, this section 1.10.9B, and the PJM Manuals, update offer parameters at any time up to 65 minutes before the applicable clock hour, including prior to the close of the Day-ahead Energy Market and prior to the close of the rebidding period specified in section 1.10.9, except that Market Sellers may not update their offers for the supply of energy, Secondary Reserve, Synchronized Reserve, Non-Synchronized Reserve, or demand reduction: (1) during the period after the close the Day-ahead Energy Market and prior to the posting of the Day-ahead Energy Market results pursuant to section 1.10.8(b); or (2) during the period after close of the rebidding period and prior to PJM announcing the results of the rebidding period pursuant to section 1.10.9(d).

(b) For generation resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) cost-based Start-up Costs; (2) cost-based No-load Costs; (3) Incremental Energy Offer; (4) Economic Minimum and Economic Maximum; (5) emergency minimum MW and emergency maximum MW; (6) ramp rate; (7) Synchronized Reserve maximum MW; (8) Secondary Reserve maximum MW; and (9) for Real-time Offers only, (i) notification time and (ii) for uncommitted hours only, Minimum Run Time. Notwithstanding the foregoing, Market Sellers of generation resources may vary the notification time for each clock hour for purposes of committing Non-Synchronized Reserve and offline Secondary Reserve in both the Day-ahead and Real-time reserve commitments.

(c) For Economic Load Response Participant resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) shutdown costs, (2) Incremental Energy Offer; (3) Economic Minimum; (4) Economic Maximum; and (5) for Real-time Offers only, (i) notification time and (ii) for uncommitted hours only, minimum down time.

(d) After the announcement of the results of the rebidding period pursuant to section 1.10.9(d), a Market Seller may submit a Real-time Offer where offer parameters may differ from the offer originally submitted in the Day-ahead Energy Market, except that a Market Seller may not submit a Real-time Offer that changes, of the offer parameters listed in section 1.10.1A(d), the MW amounts specified in the Incremental Energy Offer, MW amounts specified in the ramp rate, maximum run time, and availability; provided, however, Market Sellers of dual-fueled resources may submit Real-time Offers for such resources that change the availability of a submitted cost-based offer.

1.12 Dynamic Transfers.

(a) An entity that owns or controls a generating resource in the PJM Region may request that the Transmission Provider electrically remove all or part of the generating resource's output from the PJM Region through a Dynamic Transfer of the output to load outside the PJM Region. Such output shall not be available for economic dispatch by the Office of the Interconnection. A Market Participant otherwise eligible pursuant to section 3.2.3 to submit start-up and no-load values of a generating unit for consideration in calculation of the Energy Make Whole credit~~Operating Reserve Credit~~ shall not be so eligible if all of the output of the generating unit is transferred outside of the PJM Region by a Dynamic Transfer.

(b) An entity that owns or controls a generating resource outside of the PJM Region may request that the Transmission Provider electrically add all or part of the generating resource's output to the PJM Region through a Dynamic Transfer of the output to load inside the PJM Region. A Market Participant otherwise eligible pursuant to section 3.2.3 to submit start-up and no-load values of a generating unit for consideration in calculation of the Energy Make Whole credit~~Operating Reserve Credit~~ shall be so eligible only if all of the output of the generating unit is transferred into the PJM Region by a Dynamic Transfer.

(c) The Transmission Provider may implement Dynamic Transfers pursuant to a request under subsections (a) or (b) above, provided that the requesting entity can demonstrate to the satisfaction of the Transmission Provider that the requesting entity has arranged for the provision of signal processing and communications from the generating unit to the Office of the Interconnection and other participating control areas and remains in compliance with any other procedures and operational requirements established by the Office of the Interconnection regarding Dynamic Transfer as set forth in the PJM Manuals.

(d) An entity requesting a Dynamic Transfer shall be responsible for reserving the amount of transmission service necessary to deliver the range of the Dynamic Transfer and any required ancillary services as applicable. Firm or non-firm transmission service may be used to deliver Dynamic Schedules. Dynamic Schedules are not eligible to provide ancillary services. Only firm transmission service may be used to deliver Pseudo-Ties. Pseudo-Ties are eligible to provide Regulation, Synchronized Reserve and Non-Synchronized Reserve as further described in the PJM Manuals. An entity seeking to utilize a Dynamic Schedule to coordinate operations and beneficially manage congestion in real time with PJM may execute a mutually agreeable interregional congestion management agreement as contemplated in Section 2.6A of this Schedule. An entity seeking to utilize a Pseudo-Tie shall execute a mutually agreeable interregional congestion management agreement as contemplated in Section 2.6A of this Schedule. An entity seeking to utilize a Dynamic Transfer shall execute an agreement prescribing the requirements that must be met before PJM will implement the requested Dynamic Transfer. Dynamic Schedule transactions that occur in real time pursuant to such a congestion management agreement may utilize after-the-fact transmission reservations to account for actual energy transfers.

(e) The Market Participant shall cooperate with PJM to ensure that changes in the Dynamic Transfer value do not adversely impact PJM's management of the PJM Area Control Error in a

manner unacceptable to PJM, and, in the event that PJM, in its sole discretion, determines that the Market Participant's actions in this regard are unacceptable, PJM may terminate the Dynamic Transfer arrangement and may require such additional conditions as it deems appropriate prior to any further Dynamic Transfers.

(f) Market Sellers of generators and other sources otherwise eligible pursuant to Schedule 2 of the PJM Tariff to receive compensation for providing reactive supply and voltage control shall not be so eligible if the generating unit is outside of the PJM Region regardless of whether the generating unit is transferred into the PJM Region by a Dynamic Transfer.

3.2 Market Settlements.

If a dollar-per-MW-hour value is applied in a calculation under this section 3.2 where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW hour value is divided by the number of Real-time Settlement Intervals in the hour.

3.2.1 Spot Market Energy.

(a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with Operating Agreement, Schedule 1, section 2.

(b) Each Market Participant shall be charged for all of its Market Participant Energy Withdrawals scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price to be served in the PJM Interchange Energy Market.

(c) Each Market Participant shall be paid for all of its Market Participant Energy Injections scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price to be delivered to the PJM Interchange Energy Market.

(d) For each Day-ahead Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its Market Participant Energy Withdrawals scheduled times the Day-ahead System Energy Price and the sum of its Market Participant Energy Injections scheduled times the Day-ahead System Energy Price.

(e) For each Real-time Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its real-time Market Participant Energy Withdrawals less its scheduled Market Participant Energy Withdrawals times the Real-time System Energy Price and the sum of its real-time Market Participant Energy Injections less scheduled Market Participant Energy Injections times the Real-time System Energy Price. The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Operating Agreement, Schedule 1, section 3.1A shall be used in determining the real-time Market Participant Energy Withdrawals and Market Participant Energy Injections used to calculate Spot Market Energy charges under this subsection (e).

(f) For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the megawatts of real-time energy injections to be delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region

3.2.2 Regulation.

(a) Each Market Participant that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation Requirement of such Regulation Zone for the hour, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). A Market Participant with an hourly Regulation Obligation shall be charged the pro rata share of the sum of the Regulation market mileage clearing price credits and Regulation market capability clearing price credits for the Real-time Settlement Intervals in an hour.

Regulation Charge = Hourly Regulation Obligation Share * (sum of the Real-time Settlement Interval Regulation credits in an hour)

(b) Each Market Participant supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection shall be credited for each of its resources such that the calculated credit for each increment of Regulation provided by each resource shall be the higher of: (i) the Regulation market-clearing price; or (ii) the sum of the applicable Regulation offers for a resource determined pursuant to section 3.2.2A.1 below, the resource-specific shoulder opportunity costs described in subsection (e) of this section, the resource-specific inter-temporal opportunity costs discussed in subsection (d), and the resource-specific opportunity costs discussed in subsection (e) of this section.

(c) The Office of the Interconnection shall commit resources to provide Regulation every 30 minutes, for the clock intervals of the first 30 minutes of an hour and the second 30 minutes of an hour, up to the Regulation Requirement of such Regulation Zone. The Office of the Interconnection shall select resources in merit order, taking into account the resource's mileage Regulation offer, capability Regulation offer, and estimated resource-specific opportunity cost, all converted into their performance adjusted values as further detailed in the PJM Manuals. The total Regulation market-clearing price in each Regulation Zone shall be determined in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval. The total Regulation market-clearing price shall include: (i) the mileage Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 below shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section Operating Agreement, Schedule 1, section 1.10.1A(e).

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the resource-specific opportunity costs (in dollars) of a resource offering to sell Regulation in each regulating interval, except for hydroelectric resources, shall be equal to the area bounded by (i) Locational Marginal Price at the generation bus for the regulating resource, (ii) the resource's Final Offer, (iii) the resource's tracking ramp-rate limited expected output level if it had been

dispatched for energy in economic merit order, as further described in the PJM Manuals, and (iv) the resource's regulation set point on the energy schedule curve on which the resource is running in the PJM Interchange Energy Market. The area is divided by the resource performance score and further divided by the resource's regulation assigned megawatt to convert to dollars per megawatt.

For hydroelectric resources offering to sell Regulation in a regulating interval, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the full value of the Locational Marginal Price at that generation bus for each megawatt of Regulation capability.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the expected Locational Marginal Price at the generation bus for the hydroelectric resource and the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. Estimated opportunity costs shall be zero for hydroelectric resources for which the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those Real-time Settlement Intervals during which all available units at the hydroelectric resource were operating is higher than the actual Locational Marginal Price at the generator bus for the Real-time Settlement Interval.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating and the expected Locational Marginal Price at the generation bus for the hydroelectric resource. Estimated opportunity costs shall be zero for hydroelectric resources for which the actual Locational Marginal Price at the generator bus for the Real-time Settlement Interval is higher than the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those Real-time Settlement Intervals during which all available units at the hydroelectric resource were operating.

For the purpose of committing resources and setting Regulation market clearing prices, the Office of the Interconnection shall utilize day-ahead Locational Marginal Prices to calculate the average of the Locational Marginal Price values used in the calculation for opportunity costs for hydroelectric resources. For the purposes of settlements, the Office of the Interconnection shall

utilize the real-time Locational Marginal Prices to calculate the average of the Locational Marginal Price used in the calculation for opportunity costs for hydroelectric resources.

Opportunity costs for Economic Load Response Participant resources and regulation-only resources to provide Regulation are zero for the purpose of committing resources, setting Regulation clearing prices, and settlements.

(e) In determining the credit under subsection (b) to a Market Participant selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for (1) each Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Regulation, and (2) the two Real-time Settlement Intervals preceding the regulation commitment and the first two Real-time Settlement Intervals following the regulation commitment in accordance with the PJM Manuals and below.

The unit-specific opportunity cost in dollars, incurred during the Real-time Settlement Interval in which the Regulation obligation is fulfilled, shall be equal to the area bounded by (i) the Locational Marginal Price at the generation bus for the regulating resource, (ii) the resource's Final Offer, (iii) the generation resource's tracking ramp-rate limited expected output level if it had been dispatched in economic merit order, as further described in the PJM Manuals, and (iv) the generation resource's regulation set point, and adjusted for the performance score of the resource. Opportunity costs for Economic Load Response Participant or regulation only resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during each of the preceding two Real-time Settlement Intervals of the regulation commitment shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating Real-time Settlement Interval in order to provide Regulation and the resource's tracking expected ramp rate limited output in each of the preceding two Real-time Settlement Intervals of the regulation commitment times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in each of the preceding two Real-time Settlement Intervals of the regulation commitment and the energy offer, using the Final Offer, at the megawatt level of the Regulation set point for the resource in the initial regulating Real-time Settlement Interval, in the PJM Interchange Energy Market, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during each of the following two Real-time Settlement Intervals of the regulation commitment shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating Real-time Settlement Interval in order to provide Regulation and the resource's tracking expected ramp-rate limited output in each of the following two Real-time Settlement Intervals of the regulation commitment times, and (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in each of the following two Real-time Settlement Intervals of the regulation

commitment and the energy offer, using the Final Offer, at the megawatt level of the Regulation set point for the resource in final regulating hour, in the PJM Interchange Energy Market all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Market Participant in a Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

(g) To determine the Regulation market mileage-clearing price, the Office of the Interconnection shall adjust the submitted mileage offer for each resource in accordance with the historical performance score of that resource, and the amount of historically dispatched Regulation (mileage) calculated by the Office of the Interconnection. The maximum adjusted mileage offer of all cleared resources will set the Regulation market mileage-clearing price.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions, will be credited for Regulation mileage by multiplying the assigned MW(s) by the Regulation market mileage-clearing price, by the ratio between the requested mileage for the Regulation dispatch signal and the historic requested mileage for the Regulation dispatch signal, calculated by the Office of the Interconnection, and by the Regulation resource's performance score calculated in accordance with subsection (j) of this section. For purposes of calculating the credit for Regulation performance, if the hourly movement of the Regulation A dispatch signal equals zero, a value of 0.1 will be used in its place.

(h) The Office of the Interconnection shall divide each Regulation resource's capability offer by the historic performance score for the resource for the purposes of committing resources and setting the market clearing prices.

The Office of the Interconnection shall calculate the Regulation market capability-clearing price for each Regulation Zone by subtracting the Regulation market mileage-clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the Regulation market capability-clearing price for that market Real-time Settlement Interval.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions will be credited for Regulation capability based on the assigned MW and the capability Regulation market-clearing price multiplied by the Regulation resource's performance score calculated in accordance with subsection (j) of this section.

(i) In accordance with the processes described in the PJM Manuals, the Office of the Interconnection shall: (i) calculate inter-temporal opportunity costs for each applicable resource; (ii) include such inter-temporal opportunity costs in each applicable resource's offer to sell

frequency Regulation service; and (iii) account for such inter-temporal opportunity costs in the Regulation market-clearing price.

(j) The Office of the Interconnection shall calculate each Regulation resource's performance score. The performance score shall be a function of the difference in the energy provided versus the energy requested by the Regulation signal while scaling for the number of samples. The error measured shall be the difference of the resources response and the dispatch signal, adjusted by the assigned MW and signal dispatch of the Regulation resource. The performance score is calculated using the following equations:

Performance Score = 1 - 1/n $\sum$ Abs (Error);

Error = Average of Abs (Abs (Response - Regulation Signal) / (0.5*Interval Average Regulation Signal + 0.5*AREG)); and

n = the number of samples in the interval
AREG = assigned regulation megawatt.

The Office of the Interconnection shall calculate a performance score for each Regulation resource for each five-minute period the Regulation resource is assigned to provide Regulation.

The historic performance score will be based on a 100 clock-hour rolling average of the Real-time Settlement Interval performance scores, with consideration of the qualification score, for resources without adequate historical data, as defined in the PJM Manuals.

Regulation resources that have a Real-time Settlement Interval performance score below 25% will be ineligible for Regulation credits for that Real-time Settlement Interval.

Regulation resources that have historical performance scores fall below 40% shall be disqualified from providing Regulation until they are able to re-qualify, as defined in the PJM Manuals.

(k) During a Market Suspension where the suspension is less than or equal to 24 consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Regulation, the resources providing Regulation at the direction of the Office of the Interconnection will be compensated based on a calculated Regulation market-clearing price. Regulation market-clearing prices for each Real-time Settlement Interval associated with such Market Suspension shall be the average of the Regulation market-clearing prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

During a Market Suspension where the suspension is greater than 24 consecutive hours, if the Office of the Interconnection is assigning Regulation, resources providing Regulation at the direction of the Office of the Interconnection will be compensated based on a calculated Regulation clearing price. The Regulation clearing price for each Real-time Settlement Interval will be determined by calculating a Regulation clearing cost for the online resources providing Regulation during the Market Suspension. The resource's Regulation

clearing cost is determined by the summation of their adjusted Regulation offer and adjusted opportunity cost. The opportunity cost will be based on the resource's cost-based offer and will be determined as
follows:

> For online resources providing Regulation on a cost-based offer at the time of the Market Suspension, that cost-based offer will be used.
>
> For online resources providing Regulation on a price-based offer at the time of the Market Suspension, the Office of the Interconnection shall use the cheapest available cost-based offer based on the dispatch cost formula as defined in Operating Agreement, Schedule 1, section 6.4.1(g) using the available cost-based offers in the Office of the Interconnection system at the time of the Market Suspension.

The highest cost resource, based on this Regulation clearing cost, will set the Regulation market-clearing price for each hour of the Market Suspension.

During a Market Suspension, if the Office of the Interconnection is not assigning Regulation resources, then the Regulation market-clearing price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period and no resource-specific opportunity cost will be calculated.

During a Market Suspension, the following Regulation components for all Real-time Settlement Intervals in the Market Suspension period will be determined as follows:

(i) If the regulation performance score cannot be calculated during a Market Suspension, the historic performance score will be used for the Market Suspension period.

(ii) If the regulation mileage cannot be calculated during a Market Suspension, the mileage will be set to one (1) for the Market Suspension period.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) For each Regulation market clearing interval, the Office of the Interconnection shall conduct a Regulation three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the Regulation three-pivotal supplier test shall be capped in the interval in which they failed the test at their cost based offers as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1A(e). A Regulation supplier fails the three-pivotal supplier test in any Regulation market clearing interval in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

(b) For the purposes of conducting the three-pivotal supplier test pursuant to this section, the following applies:

(i) The Regulation three-pivotal supplier test will include in the definition of available supply all offer megawatts from resources capable of satisfying the Regulation Requirement of the PJM Region multiplied by the historic performance score of the resource for which the capability cost-based offer plus the mileage cost-based offer plus any eligible opportunity costs is no greater than 150% of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The Regulation three-pivotal supplier test will apply on a Regulation supplier basis (i.e. not a resource by resource basis) and only the Regulation suppliers that fail the three-pivotal supplier test will have their Regulation offers capped. A Regulation supplier for the purposes of this section includes corporate affiliates. Regulation from resources controlled by a Regulation supplier or its affiliates, whether by contract with unaffiliated third parties or otherwise, will be included as Regulation of that Regulation supplier. Regulation provided by resources owned by a Regulation supplier but controlled by an unaffiliated third party, whether by contract or otherwise, will be included as Regulation of that third party.

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the Regulation Requirement for the Regulation clearing interval to determine the residual supply index. Where the residual supply index for Regulation three pivotal suppliers is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 ~~Operating Reserves~~Energy Uplift.

(a) A Market Seller's pool-scheduled resources ~~capable of providing Operating Reserves~~ shall be credited as specified below for Energy Make Whole credits. ~~based on the applicable offer for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that sections 3.2.3A, 3.2.3A.001, and 3.2.3A.01 below do not meet the Synchronized Reserve Requirements, the Primary Reserve Requirements, and the 30-minute Reserve Requirements, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the day-ahead market. PJMSettlement shall be the Counterparty to the purchases and sales of Operating Reserve in the PJM Interchange Energy Market.~~

(b) Day-ahead Energy Make Whole credits ~~The following determination~~ shall be ~~made~~ calculated in the following manner for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for Start-up Costs and No-load Costs and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. PJM shall also (i) determine whether any resources were scheduled in the Day-ahead Energy Market to provide Black Start ~~s~~Service, Reactive Services or transfer interface control during the Operating Day because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day in order to minimize the total cost of Operating Reserves associated with the provision of such services and reflect the most accurate possible expectation of real-time operating conditions in the day-ahead model, which resources would not have otherwise been committed in the day-ahead security-constrained dispatch and (ii) report on the day following the Operating Day the megawatt quantities scheduled in the Day-ahead Energy Market for the above-enumerated purposes for the entire RTO.

Except as provided in section 3.2.3(n) below, if the total offered price for Start-up Costs (shutdown costs for Economic Load Response Participant resources) and No-load Costs and energy summed over all Day-ahead Settlement Intervals exceeds the total value summed over all Day-ahead Settlement Intervals, the difference shall be credited to the Market Seller as ~~a~~ day-ahead ~~Operating Reserve~~Energy Make Whole credits.

However, for the Day-ahead Settlement Intervals in which the resource is scheduled to provide energy in the Operating Day and the resource actually provides energy in at least one Real-time Settlement Interval in an hour that corresponds to such scheduled Day-ahead Settlement Intervals, a resource's day-ahead ~~Operating Reserve~~Energy Make Whole credit shall be reduced by the greater of zero or the difference of the resource's ~~D~~day-ahead ~~Operating Reserve~~Energy Make Whole ~~T~~target and the b~~B~~alancing ~~Operating Reserve~~Energy Make Whole ~~T~~target, as determined below.

A resource's d~~D~~ay-ahead ~~Operating Reserve~~Energy Make Whole ~~T~~target shall be determined in accordance with the following equation:

(A + B) - C

Where:

A = Start-up Costs

B = the sum of day-ahead No-load Costs and energy over the applicable Real-time Settlement Intervals that correspond with Day-ahead Settlement Intervals in which the resource is scheduled. The day-ahead No-load Costs and energy are divided by twelve to determine the cost for each Real-time Settlement Interval.

C = the sum of the day-ahead revenues calculated for each Real-time Settlement Interval that corresponds with a Day-ahead Settlement Interval in which the resource is scheduled, where the day-ahead revenue for each such Real-time Settlement Interval equals the product of the megawatt amount of energy scheduled in the Day-ahead Energy Market and the Day-ahead Price at the applicable pricing point for the resource divided by twelve.

A resource's ~~B~~balancing ~~Operating Reserve~~Energy Make Whole ~~T~~target shall be determined in accordance with the following equation:

D – (E + F)

Where:

D = the Real-time Cost, as defined in subsection 3.2.3(e-2)(ii) of this section, ~~sum of Start-up Costs and No-load Costs and the incremental cost of energy~~ summed over all Real-time Settlement Intervals that correspond to the Day-ahead Settlement Intervals in which the resource was scheduled;

E = [(the megawatt amount of energy provided in the Real-time Energy Market minus the megawatt amount of energy scheduled in the Day-ahead Energy Market) multiplied by the Real-time Price at the applicable pricing point for the resource] plus the sum of the day-ahead revenues as determined in part C of the above formula for determining the Day-ahead ~~Operating Reserve~~Energy Make Whole ~~T~~target, summed over the ~~applicable~~ Real-time Settlement Intervals that correspond to the Day-ahead Settlement Intervals in which the resource was scheduled; and

F = the sum of all Other Market ~~r~~Revenues, as defined in subsection 3.2.3(e-2)(ii) of this section, ~~earned for providing Secondary Reserves, Non-Synchronized Reserves, and Reactive Services~~ over the ~~applicable~~ Real-time Settlement Intervals that correspond to the Day-ahead Settlement Intervals in which the resource was scheduled.

~~The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this section 3.2.3(b) to real-time deviations or real-time load share plus exports, pursuant to Operating Agreement, Schedule 1, section 3.2.3(p) below, depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day. Allocation to real-time load share under this subsection (b) shall not apply to Direct Charging Energy.~~

~~(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:~~

~~(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate~~

~~in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations.~~

~~(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve credits, identified as RA Credits for Reliability, shall be allocated according to ratio share of real time load plus export transactions.~~

~~(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.~~

~~(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve credits shall be allocated according to the following provisions:~~

~~(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.~~

~~(B) If the Office of the Interconnection directs a resource not covered by section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.~~

~~(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.~~

(c) The sum of the foregoing credits calculated in accordance with section 3.2.3(b) plus any unallocated charges from section 3.2.3(h) and Operating Agreement, Schedule 1, section 5.1.7, and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of ~~Operating Reserves~~Energy Make Whole credits in the Day-ahead Energy Market.

(d) The cost of ~~Operating Reserves~~Energy Make Whole credits in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load ((a) net of Behind The Meter Generation expected to be operating, but not to be less than zero; and (b) excluding Direct Charging Energy), accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day and accepted Up-to Congestion Transactions in the Day-ahead Energy Market in megawatt-hours for the Operating Day at the sink of the transaction; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside such area pursuant to Operating Agreement, Schedule 1, section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of ~~Operating Reserves~~Energy Make Whole credits in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Tariff, Schedule 6A. The cost of ~~Operating Reserves~~Energy Make Whole credits in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load ((a) net of operating Behind The Meter Generation; and (b) excluding Direct Charging Energy) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

~~(e)~~ (i) Pool-scheduled generation resources that operate for at least one Real-time Settlement Interval within the pool-scheduled commitment period are eligible for balancing Energy Make Whole credits as further detailed in this section and in the PJM Manuals. Balancing Energy Make Whole credits eligibility for Economic Load Response Participant resources is detailed in Operating Agreement, Schedule 1, section 3.2.3(o-1) of this section. A pool-scheduled generation resource's eligibility for balancing Energy Make Whole credits begins at the first Real-time Settlement Interval of a pool-scheduled commitment. The generation resource remains eligible for balancing Energy Make Whole credits until the later of:

1) the Real-time Settlement Interval corresponding to the end of its Day-ahead Energy Market commitment or the end of its Minimum Run Time, as applicable

or

2) the Real-time Settlement Interval when the resource is no longer running under the direction of the Office of the Interconnection.

Additionally, generation resource types with no soak process in the Start-up Cost are eligible for balancing Energy Make Whole credits for a pre-commitment period prior to the first Real-time Settlement Interval of the pool-scheduled commitment to account for ramping costs. The pre-commitment period begins with the Real-time Settlement Interval when a generation resource comes online but may not begin earlier than four Real-time Settlement Intervals (20 minutes) prior to the first Real-time Settlement Interval of the pool-scheduled commitment. However, a generation resource is only eligible for this pre-commitment period if the price and megawatt quantities submitted as part of its Incremental Energy Offer, using the lesser of the Final Offer or Committed Offer as determined using the Actual MWh during the pre-commitment period, are less than or equal to the price and megawatt quantities of its Incremental Energy Offer using the Committed Offer for the first hour of the commitment. Generation resource types with a soak process in the Start-up Cost are not eligible during the pre-commitment period.

Pool-scheduled generation resources that are released by the Office of Interconnection and ramping offline are additionally eligible for balancing Energy Make Whole credits for post-commitment Real-time Settlement Intervals until the Real-time Settlement Interval that the generation resource goes offline; however, eligibility shall not extend beyond the Real-time Settlement Interval in which the resource is no longer running under the direction of the Office of Interconnection plus the number of Real-time Settlement Intervals corresponding to the allowable ramp down period for the resource type, as specified in the PJM Manuals. However, a generation resource is only eligible for this post-commitment period if the price and megawatt quantities submitted as part of its Incremental Energy Offer, using the lesser of the Final Offer or Committed Offer as determined using the Actual MWh during the post-commitment period, is less than or equal to the price and megawatt quantities of its Incremental Energy Offer using the Committed Offer for the last hour of the commitment.

~~At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following Segments: 1) the greater of their day-ahead schedules and minimum run time specified at the time of commitment (minimum down time specified at the time of commitment for Economic Load Response Participant resources); and 2) any block of Real-time Settlement Intervals the resource operates at PJM's direction in excess of the greater of its day-ahead schedule and minimum run time specified at~~

~~the time of commitment (minimum down time specified at the time of commitment for Economic Load Response Participant resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two Segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time specified at the time of commitment (minimum down time specified at the time of commitment for Demand Resources) and Segment 2 will include the remainder of the contiguous Real-time Settlement Intervals when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.~~

(ii) The balancing Energy Make Whole credit calculation will be conducted on a segmented basis. For each Operating Day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two Segments for each resource.

The first Segment will be defined as the greater of the applicable day-ahead commitment and Minimum Run Time specified at the time of commitment (minimum down time specified at the time of commitment for Economic Load Response Participant resources). Further, if a generation resource is no longer running under the direction of the Office of the Interconnection within 30 minutes after the end of the first Segment, the first Segment will also include the remainder of the Real-time Settlement Intervals in which the resource operated at the direction of the Office of the Interconnection.

The second Segment will be defined as any block of contiguous Real-time Settlement Intervals the resource runs under the direction of the Office of the Interconnection in excess of the first Segment.

Notwithstanding the foregoing, each Segment shall be limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

~~A Generation Capacity Resource that operates outside of its unit-specific parameters will not receive Operating Reserve Credits nor be made whole for such operation when not dispatched by the Office of the Interconnection, unless the Market Seller of the Generation Capacity Resource can justify to the Office of the Interconnection that operation outside of such unit-specific parameters was the result of an actual constraint.~~

(iii) If a Market Seller submits an offer parameter that exceeds the applicable approved parameter limit on a parameter-limited schedule for a generation resource and such parameter affects the MW dispatch level of the resource in a given settlement interval, the resource will remain eligible for the energy uplift credit calculation but shall not recover any costs incurred during the affected settlement intervals. If such parameter impacts the commitment decision in a manner that could lead to the Office of the Interconnection committing the generation resource to produce energy for longer than it otherwise would have, the resource will not be eligible for the energy uplift credit calculation for the commitment duration. A generation resource that is the subject to an offer parameter on a parameter-limited schedule that exceeds its approved parameter limits may still be eligible for energy uplift credits if the Market Seller of such resource

can justify to the Office of the Interconnection that the need to operate outside of such unit-specific parameters was the result of an actual constraint.

~~Such~~ A Market Seller shall provide to the Market Monitoring Unit and the Office of the Interconnection its request to receive ~~Operating Reserve~~energy uplift c~~C~~redits ~~and/or to be made whole~~ for such operation, along with documentation explaining in detail the reasons for operating its resource outside of its unit-specific parameters, within thirty calendar days following the issuance of the billing statement for the Operating Day. The Market Seller shall also respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection. The Market Monitoring Unit shall evaluate such request for compensation and provide its determination of whether there was an exercise of market power to the Office of the Interconnection by no later than twenty-five calendar days after receiving the Market Seller's request for compensation. The Office of the Interconnection shall make its determination whether the Market Seller justified that it is entitled to receive ~~Operating Reserve~~energy uplift c~~C~~redits ~~and/or be made whole~~ for such operation of its resource for the day(s) in question, by no later than thirty calendar days after receiving the Market Seller's request for compensation.

(iv) Nuclear generation resources shall not be eligible for ~~Operating Reserve~~energy uplift payments unless: 1) the Office of the Interconnection directs such resources to reduce output, in which case, such units shall be compensated in accordance with Tariff, Attachment K-Appendix, section 3.2.3(f) and the parallel provision of Operating Agreement, Schedule 1, section 3.2.3(f); or 2) the resource submits a request for a risk premium to the Market Monitoring Unit under the procedures specified in Tariff, Attachment M – Appendix, section II.B. A nuclear generation resource (i) must submit a risk premium consistent with its agreement under such process, or, (ii) if it has not agreed with the Market Monitoring Unit on an appropriate risk premium, may submit its own determination of an appropriate risk premium to the Office of the Interconnection, subject to acceptance by the Office of the Interconnection, with or without prior approval from the Commission.

(e-1) The Tracking Ramp Limited Desired (TRLD) metric is used in the calculation of balancing Energy Make Whole credits and generator deviation charges as a representation of the level at which the resource would be desired if operating as requested by the Office of the Interconnection. There are two Tracking Ramp Limited Desired metrics, one measured in MW (power) and the other measured in MWh (energy), each of which are calculated as described below and as further detailed in the PJM Manuals. The Tracking Ramp Limited Desired MWh (energy) calculated for each Real-time Settlement Interval shall be used in the calculation of balancing Energy Make Whole credits and generator deviations. The Tracking Ramp Limited Desired MWh (energy) value represents the expected energy produced between the start of the Real-time Settlement Interval and the end of the Real-time Settlement Interval.

For purposes of this Operating Agreement, Schedule 1, section 3.2.3, the minimum operating limit used herein shall be the Economic Minimum unless the Office of the Interconnection has declared Minimum Generation Emergency conditions, in which case it shall be the emergency

minimum. Also, the maximum operating limit shall be the Economic Maximum unless the Office of the Interconnection has declared Maximum Emergency conditions, in which case it shall be the emergency maximum.

(i) Tracking Ramp Limited Desired MW (power) is an adjusted metric that accounts for the impact of Regulation and reserve assignments or manual dispatch instructions.

The Tracking Ramp Limited Desired MW (power) calculation starts at time t_0, which is when a generation resource is first expected by the Office of Interconnection to be online or when a generation resource is dispatchable, while honoring soak time differences, as further detailed in the PJM Manuals.

The Tracking Ramp Limited Desired MW (power) metric will be calculated as follows. For the Real-time Settlement Interval equal to t_0,

If a generation resource does not have a soak process and is directed to come online as soon as possible,

TRLD MW (power) = 0

Otherwise,
TRLD MW (power)
= Max [Min (LMP Desired MW, Dispatch MW), Tracking Desired Economic Minimum]

Where:
LMP Desired MW = the generation resource's expected output level based on its Final Offer at the Real-time Locational Marginal Price from the dispatch run at the applicable pricing point
Dispatch MW = energy dispatch signal MW from the dispatch run
Tracking Desired Economic Minimum = the generation resource's minimum operating limit, as specified in Operating Agreement, Schedule 1, section 3.2.3(e-1), unless any of the following conditions occur,

- If a resource is requested to increase output due to a transmission constraint or other reliability issue, Tracking Desired Economic Minimum = the lower limit from the manual dispatch instruction as directed by the Office of the Interconnection.

- If the resource's minimum operating limit increases by more than 5% of the resource's minimum operating limit at the time of commitment, the minimum operating limit at the time of commitment will be used.

For each Real-time Settlement Interval after the resource's initial start time, t_0, Tracking Ramp Limited Desired MW (power) shall be calculated as follows:

$$TRLD\ MW_t\ (power) = TRLD\ MW_{t-1} \pm Ramp_t$$

Where:

t = Start time of Real-time Settlement Interval for which the metric is being calculated

Ramp = Increase or decrease in MW calculated using the Real-time Locational Marginal Price from the dispatch run at the applicable pricing point, the resource's Final Offer, and the ramp rate parameters. The increase or decrease in MW is restricted by the most limiting of the following parameters among the ramp rate, the Tracking Desired Economic Minimum, and the Tracking Desired Economic Maximum, where:

Tracking Desired Economic Minimum = defined above in the calculation for $TRLD\ MW_{t0}$

Tracking Desired Economic Maximum = the generation resource's maximum operating limit unless any one of the following conditions occur:

- If a resource is requested to decrease output due to a transmission constraint or other reliability issue, Tracking Desired Economic Maximum = the upper limit from the manual dispatch instruction as directed by the Office of the Interconnection.

- If a resource's maximum operating limit decreases by more than 5% of the resource's maximum operating limit at the time of commitment, the maximum operating limit at the time of commitment will be used.

The Tracking Ramp Limited Desired MW (power) value will be further adjusted, as specified below, if the resource has a regulation or reserve assignment and is unable to provide such assignment while generating the initial Tracking Ramp Limited Desired MW due to the resource's applicable operating parameters.

- If the Tracking Ramp Limited Desired MW is above the highest MW point at which the resource can provide the Regulation or reserve assignments, the Tracking Ramp Limited Desired MW will be lowered to the highest point at which it can provide the assignment(s) based on the resource's applicable operating parameters.

- If the Tracking Ramp Limited Desired MW is below the lowest MW point at which the resource can provide the Regulation assignment, the Tracking Ramp Limited Desired MW will be increased to the lowest point at which it can provide the regulation assignment based on the resource's applicable operating parameters.

This adjusted Tracking Ramp Limited Desired MW value is used in calculating the Tracking Ramp Limited Desired MW (power) for subsequent intervals.

(ii) An unadjusted Tracking Ramp Limited Desired MW (power) that excludes the impact of Regulation and reserve assignments or manual dispatch instructions is also calculated for conversion to an unadjusted Tracking Ramp Limited Desired MWh (energy) metric which is used in the Other Market Revenue and Opportunity Cost Owed calculations described in subsection 3.2.3(e-2)(i). The unadjusted Tracking Ramp Limited Desired MW (power) metric will be calculated as follows.

For the Real-time Settlement Interval equal to $t_{0,}$ the unadjusted Tracking Ramp Limited Desired MW (power) equals the Tracking Ramp Limited Desired MW $(power)_{t0}$ as calculated in subsection (i) directly above excluding the impact of regulation and reserve assignments or manual dispatch instructions.

For each Real-time Settlement Interval after the start time, t_0, the unadjusted Tracking Ramp Limited Desired MW (power) shall be calculated as follows:

$$\text{unadjusted TRLD } MW_t \text{ (power)} = \text{unadjusted TRLD } MW_{t-1} \pm Ramp_t$$

Where:

t = Start time of Real-time Settlement Interval for which the metric is being calculated

Ramp = Increase or decrease in MW calculated using the Real-time Locational Marginal Price from the dispatch run at the applicable pricing point, the resource's Final Offer, and the ramp rate parameters. The increase or decrease in MW is restricted by the most limiting parameter among the ramp rate, the unadjusted economic minimum, and the unadjusted economic maximum, where:

unadjusted economic minimum = minimum operating limit for the Real-time Settlement Interval unless such minimum operating limit increased by more than 5% of the resource's minimum operating limit at the time of commitment, in which case the minimum operating limit at the time of commitment shall be used.

unadjusted economic maximum = maximum operating limit for the Real-time Settlement Interval unless such maximum operating limit decreased by more than 5% of the resource's maximum operating limit at the time of commitment, in which case the maximum operating limit at the time of commitment shall be used.

(iii) The Tracking Ramp Limited Desired MW (power) calculations in Operating Agreement, Schedule 1, section 3.2.3(e-1)(i) and (ii) above will continue until the resource goes offline; however, if a generation resource trips or is taken offline at the request of the Market Seller prior to the later of the end of the Day-ahead Energy Market commitment or the end of the Minimum Run Time, the values will continue to be

calculated per the calculations defined above until the later of the end of the Day-ahead Energy Market commitment or the end of the Minimum Run Time.

Further, once the Office of the Interconnection releases a generation resource to go offline, provided that the resource actually goes offline following such direction, the Tracking Ramp Limited Desired MW shall be calculated using only the ramp down parameters such that the Tracking Ramp Limited Desired MW is incrementally ramped down to its minimum output, irrespective of the real-time LMP. During this time period, the unadjusted Tracking Ramp Limited Desired MW (power) will equal the Tracking Ramp Limited Desired MW (power) unless the resource has been manually dispatched offline, in which case the unadjusted Tracking Ramp Limited Desired MW (power) will continue as specified above in Operating Agreement, Schedule 1, section 3.2.3(e-1)(ii) until the manual dispatch instruction ends.

TRLD MW_t (power) =

Max (TRLD MW_{t-1} – Down $Ramp_t$, Tracking Desired Economic $Minimum_t$)

Where Down Ramp = Decrease in MW utilizing the resource's down ramp rate parameter.

(iv) The Tracking Ramp Limited Desired MW (power) and unadjusted Tracking Ramp Limited Desired MW (power) metrics will be converted to the Tracking Ramp Limited Desired MWh (energy) metrics that shall be used in the calculation of balancing Energy Make Whole credits and generator deviations. For all Real-time Settlement Intervals prior to the start time of the Tracking Ramp Limited Desired MW (power) calculations, t_0 as defined above, both the Tracking Ramp Limited Desired MWh (energy) and the unadjusted Tracking Ramp Limited Desired MWh (energy) shall be equal to the resource's Actual MWh for that Real-time Settlement Interval. For purposes of this section, Actual MWh equals the Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Tariff, Attachment K-Appendix, section 3.1A and parallel provisions in Operating Agreement, Schedule 1, section 3.1A.

For each Real-time Settlement Interval after the Office of the Interconnection releases a generation resource to go offline and the resource's Actual MWh is below the minimum operating limit, the Tracking Ramp Limited Desired MWh (energy) and the unadjusted Tracking Ramp Limited Desired MWh (energy) shall be equal to Actual MWh of the resource.

For all other Real-time Settlement Intervals, the Tracking Ramp Limited Desired MWh (energy) shall equal the expected energy produced between the start of the Real-time Settlement Interval and the end of the Real-time Settlement Interval based on the Tracking Ramp Limited Desired MW (power) at the start and at the end of the Real-time Settlement Interval and the resource's ramping capability, as further described in the PJM Manuals. The unadjusted Tracking Ramp Limited Desired MWh (energy) shall equal the expected energy produced between the start of the Real-time Settlement Interval and the

end of the Real-Time Settlement Interval based on the unadjusted Tracking Ramp Limited Desired MW (power) at the start and at the end of the Real-time Settlement Interval and the resource's ramping capability, as further described in the PJM Manuals.

(v) The Tracking Ramp Limited Desired MW (power) and MWh (energy) values described above in subsections Operating Agreement, Schedule 1, section 3.2.3(e-1)(i) and (ii), as may be qualified by (iii), and (iv) of this section may be further adjusted as described in the PJM Manuals to account for instances where the Office of the Interconnection is unable to dispatch the system using the real-time security constrained economic dispatch system and/or where the real-time security-constrained economic dispatch application is providing dispatch signals inconsistent with the resource's offer data, or other abnormal dispatch scenarios.

(e-2) For generating resources, balancing Energy Make Whole ~~C~~credits received pursuant to this section shall be equal to the lesser of the Tracking Balancing Energy Make Whole Credit, as calculated in Step 1 below in Operating Agreement, Schedule 1, section 3.2.3(e-2)(i), and the Actual Balancing Energy Make Whole Credit, as calculated in Step 2 below in Operating Agreement, Schedule 1, section 3.2.3(e-2)(ii), for each Segment in the Operating Day, except as provided in this Operating Agreement, Schedule 1, section 3.2.3(m). Balancing Energy Make Whole credits for Economic Load Response Participant resources shall be equal to the credits as determined in Operating Agreement, Schedule 1, section 3.3.A~~positive difference between a resource's Total Operating Reserve Offer, and the total value of the resource's energy in the Day-ahead Energy Market plus any credit or change for quantity deviations, at PJM dispatch direction (excluding quantity deviations caused by an increase in the Market Seller's Real-time Offer), from the Day-ahead Energy Market during the Operating Day at the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for Segment 2 shall exclude start up (shutdown costs for Economic Load Response Participant resources) costs for generation resources~~.

~~Except as provided in section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to section 3.2.3(b), and less the absolute value of any negative Synchronized Reserve lost opportunity cost credit, as determined in section 3.2.3A(f)(iv) below, and less the absolute value of any negative Non-Synchronized Reserve lost opportunity cost credit determined in section 3.2.3.A.001(d)(iii) below, and less any amounts credited for providing Reactive Services as specified in section 3.2.3B, and the absolute value of any negative Secondary Reserve lost opportunity cost credit, as determined in section 3.2.3A.01(f)(iv) below, and plus the sum of the Market Revenue Neutrality Offsets for Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve, shall be credited to the Market Seller.~~

~~Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding Real-time Settlement Interval(s) in which the Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve credits accrued,~~

~~provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each Real-time Settlement Interval the unit operates in condensing and generation mode.~~

(i) Step 1: Calculate Tracking Balancing Energy Make Whole credit for the Segment using Tracking Ramp Limited Desired MWh.

Tracking Balancing Energy Make Whole Credit = A – B

Where

A = $-1 \times \sum_t$ Tracking Balancing Net Revenue$_t$

Where t = the eligible Real-time Settlement Intervals in the applicable Segment

B = Day-ahead Energy Make Whole Credit as determined pursuant to section 3.2.3(b) if the Segment is the first Segment. For all other Segments, B = 0.

Tracking Balancing Energy Make Whole Credit shall not be less than zero.

The Tracking Balancing Net Revenue for each Real-time Settlement Interval in the Segment shall be calculated in accordance with the following equation:

Tracking Balancing Net Revenue$_t$ = (DA Revenue$_t$ + Balancing Revenue$_t$ + Other Market Revenue$_t$ + Opportunity Cost Owed$_t$) - Real-time Cost$_t$

Where

t = the Real-time Settlement Interval

DA Revenue = Day-ahead Energy Market Revenue for the Real-time Settlement Interval in accordance with the following equation:

Day-ahead Scheduled MWh × Day-ahead LMP

Balancing Revenue = Balancing Energy Market Revenue in accordance with the following equation:

(Tracking Ramp Limited Desired MWh ─ Day-ahead Scheduled MWh) × Real-time LMP ─ Company Responsible Negative Revenues

Where: Company Responsible Negative Revenues = any negative balancing revenues in excess of the Day-ahead Energy Market revenue that results from the Market Participant's actions reducing the resource's flexibility as further specified in the PJM Manuals. This is calculated as:

MW unavailable due to limited flexibility × Min (Day-ahead LMP ─ Real-Time LMP, 0)

Other Market Revenue = SR + SecR + NSR + Reactive + LOC + Reg

Where
SR = any potential credits for providing Synchronized Reserve determined in accordance with the credit calculations in Operating Agreement, Schedule 1, section 3.2.3A(b) less the resource's Synchronized Reserve offer price, in dollars, included in the resource's Synchronized Reserve potential lost opportunity cost credit in Operating Agreement, Schedule 1, section 3.2.3A(f)(iv).

SecR = any potential credits for providing Secondary Reserve determined in accordance with the credit calculations in Operating Agreement, Schedule 1, section 3.2.3A.01(b)

NSR = any amounts credited for providing Non-Synchronized Reserve as specified in Operating Agreement, Schedule 1, section 3.2.3A.001(b)

Reactive = any potential credits for providing Reactive Services determined in accordance with the credit calculations in Operating Agreement, Schedule 1, section 3.2.3B

LOC = any potential lost opportunity cost credits determined in Operating Agreement, Schedule 1, sections 3.2.3(f) – 3.2.3(f-6).

Reg = any potential Regulation opportunity cost amounts determined in accordance with the calculations for use in settlements in Operating Agreement, Schedule 1, section 3.2.2.

Opportunity Cost Owed = the sum of the potential opportunity costs owed for Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve as determined in accordance with Sections 3.2.3A(f)(iv), 3.2.3A.001(d)(iii) and 3.2.3A.01(f)(iv), respectively.

For the purposes of the above Other Market Revenue and Opportunity Cost Owed calculations, the potential credits and costs are determined using the calculations referenced above and the assumption that the resource was increased or decreased from the unadjusted Tracking Ramp Limited Desired MWh in order to provide the assignment or PJM directed MW as further described in the PJM Manuals.

Real-time Cost = (Incremental Offer + No Load Cost + Start-Up Cost)
Where

Incremental Offer = Real-time incremental energy offer, in dollars, based on the area under the incremental energy offer curve calculated using the Tracking Ramp Limited Desired MWh

No Load = Real-time No-load Cost

Start-Up = Real-time Start-Up Cost, if it is a Real-time Settlement Interval in the first Segment

The offer used for calculating Real-time Cost shall be the lesser of the Committed Offer or Final Offer based on the offer with the lowest total cost for the hour.

The above Balancing Revenue and Real-time Cost calculations shall be further modified for Real-time Settlement Intervals preceding the start of the commitment for generation resource types with no soak process in the Start-up Cost by capping the Tracking Ramp Limited Desired MWh (energy) at the minimum operating limit for such interval.

The above Balancing Revenue and Real-time Cost calculations shall be reduced by the costs incurred and revenues received in the applicable Real-time Settlement Intervals for generation resource types with a soak process in the Start-up Cost when the Tracking Ramp Limited Desired MWh (energy) indicate the unit is not dispatchable by the Office of the Interconnection during a Real-time Settlement Interval when it was scheduled to be dispatchable since those costs and revenues may already be included in the Start-Up Cost as further defined in the PJM Manuals.

During Real-time Settlement Intervals where a Flexible Resource is self-scheduled and was committed by the Office of the Interconnection in the Day-ahead Energy Market for the same Real-time Settlement Interval, the above calculation will use the Tracking Balancing Net Revenues that the resource would have received if it had followed PJM real-time commitment instructions and remained offline; provided that if the unit is taken over by company to run as self-scheduled prior to the Minimum Run Time of a pool scheduled commitment elapsing, this shall only apply to those Real-time Settlement Intervals beyond the Minimum Run Time.

(ii) Step 2: Calculate balancing Energy Make Whole credits for the Segment using Actual MWh.

Actual Balancing Energy Make Whole Credit = A – B

Where

$A = -1 \times \sum_t$ Actual Balancing Net Revenue$_t$

Where t = the eligible Real-time Settlement Intervals in the applicable Segment

B = Day-ahead Energy Make Whole Credit as determined pursuant to section 3.2.3(b) if the Segment is the first Segment; else, 0

Actual Balancing Energy Make Whole Credit shall not be less than zero.

The Actual Balancing Net Revenue for each Real-time Settlement Interval in the Segment shall be calculated in accordance with the following equation. For purposes of this section, the Actual MWh equals the Revenue Data for Settlements determined for

each Real-time Settlement Interval in accordance with Operating Agreement, Schedule 1, section 3.1A.

Actual Balancing Net Revenue$_t$ = (DA Revenue$_t$ + Balancing Revenue$_t$ + Other Market Revenue$_t$) - Real-time Cost$_t$

Where
t = the Real-time Settlement Interval

DA Revenue = Day-ahead Energy Market Revenue for the Real-time Settlement Interval in accordance with the following equation:

Day-ahead Scheduled MWh × Day-ahead LMP

Balancing Revenue = Balancing Energy Market Revenue for the Real-time Settlement Interval in accordance with the following equation:

(Actual MWh – Day-ahead Scheduled MWh) × Real-time LMP ─ Company Responsible Negative Revenues

Where: Company Responsible Negative Revenues = any negative balancing revenues in excess of the DA revenue based on the Market Participant's actions reducing flexibility as further specified in the PJM Manuals. This is calculated as:

MW unavailable due to limited flexibility × Min (Day-ahead LMP ─ Real-Time LMP, 0)

Other Market Revenue = SR + SecR + NSR + Reactive + LOC + Reg

Where:
SR = any amounts credited for providing Synchronized Reserve equal to the credits as determined in Operating Agreement, Schedule 1, section 3.2.3A(b) less the resource's Synchronized Reserve offer price, in dollars, included in the resource's Synchronized Reserve lost opportunity cost credit calculation in Operating Agreement, Schedule 1, section 3.2.3A(f)(iv)

SecR = any amounts credited for providing Secondary Reserve as determined in Operating Agreement, Schedule 1, section 3.2.3A.01 (b)

NSR = any amounts credited for providing Non-Synchronized Reserve as determined in Operating Agreement, Schedule 1, section 3.2.3A.001(b)

Reactive = any amounts credited for providing Reactive Services as determined in Operating Agreement, Schedule 1, section 3.2.3B

LOC = any lost opportunity costs credits as determined in Operating Agreement, Schedule 1, sections 3.2.3(f) – 3.2.3(f-6); and

Reg =any Regulation opportunity cost amounts as calculated for purposes of settlements in Operating Agreement, Schedule 1, section 3.2.2

Real-time Cost = (Incremental Offer + No Load + Start-Up)

Incremental Offer = Real-time incremental energy offer, in dollars, based on the area under the incremental energy offer curve calculated using the Actual MWh

No Load = Real-time No-load Cost

Start-Up = Real-time Start-Up Cost, if it is within the first Segment

The offer used for calculating Real-time Cost shall be the Final Offer for the hour.

The above Balancing Revenue and Real-time Cost calculations shall be reduced by the costs incurred and revenues received in the applicable Real-time Settlement Intervals for generation resource types with a soak process in the Start-up Cost when the Actual MWh indicate the resource is not dispatchable by the Office of the Interconnection during a Real-time Settlement Interval when it was scheduled to be dispatchable by the Office of the Interconnection since those costs and revenues may already be included in the Start-Up Cost as further defined in the PJM Manuals.

The above Balancing Revenue and Real-time Cost calculation shall be further modified for Real-time Settlement Intervals preceding the start of the commitment for generation resource types with no soak process in the Start-up Cost, by capping the Actual MWh at the minimum operating limit for each such interval.

(iii) In the event of a real-time Market Suspension, if the Office of the Interconnection and the Market Monitoring Unit determine that the generation resource was not following dispatch instructions, the generation resource shall be ineligible for balancing Energy Make Whole credits. If the generation resource is eligible during a real-time Market Suspension, the balancing Energy Market Whole credit shall be equal to the actual balancing Energy Make Whole credit, as determined in subsection 3.2.3(e-2)(ii) of this section.

(iv) A price-sensitive pool-scheduled import transaction shall receive balancing Energy Make Whole credits equal to the positive difference between a transaction's offer, and the total value of the transaction's energy in the Day-ahead Energy Market plus any credit or charge for quantity deviations from the Day-ahead Energy Market at the real-time LMP(s) applicable to the sink of the transaction summed over all Real-time Settlement Intervals in the Operating Day.

(f) A Market Seller of a unit not defined in subsection (f-1), (f-2), or (f-4) hereof (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3(c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the LOC Deviation times (B) the Locational Marginal Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C. A Market Seller of a unit defined in subsection (f-1), (f-2), (f-3), (f-4), or (f-5) that is reduced using a generator output constraint to honor a stability limitation is not eligible for credits under this section 3.2.3(f) for the MWh reduction associated with honoring the stability limit. If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.11.6, where the suspension is greater than twenty-four (24) consecutive hours, resources will not be compensated for lost opportunity costs.

(f-1) With the exception of Market Sellers of Flexible Resources that submit a Real-time Offer greater than their resource's Committed Offer in the Day-ahead Energy Market, a Market Seller of a Flexible Resource shall be compensated for lost opportunity cost, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described in section 3.2.3(f).

(ii) If the unit is scheduled to produce energy in the Day-ahead Energy Market for a Day-ahead Settlement Interval, but the unit is not called on by the Office of the Interconnection and does not operate in the corresponding Real-time Settlement Interval(s), then the Market Seller shall be credited in an amount equal to the higher of:

1) the product of (A) the amount of megawatts committed in the Day-ahead Energy Market for the generating unit, and (B) the Real-time Price at the generation bus for the generating unit, minus the sum of (C) the Total Lost Opportunity Cost Offer plus No-load Costs, plus (D) the Start-up Cost, divided by the Real-time Settlement Intervals committed for each set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market. This equation is represented as (A*B) - (C+D). The startup cost, (D), shall be excluded from this calculation if the unit operates in real time following the Office

of the Interconnection's direction during any portion of the set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market, or

2) the Real-time Price at the unit's bus minus the Day-ahead Price at the unit's bus, multiplied by the number of megawatts committed in the Day-ahead Energy Market for the generating unit.

(f-2) A Market Seller of a hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3(c), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-4) A Market Seller of a wind or solar generating unit, Hybrid Resource or Energy Storage Resource Model Participant that is pool-scheduled or self-scheduled, has SCADA capability to transmit and receive instructions from the Office of the Interconnection, has provided data and established processes to follow PJM basepoints pursuant to the requirements for wind or solar generating units, Hybrid Resource or Energy Storage Resource Model Participant as further detailed in this Agreement, the Tariff and the PJM Manuals, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the LOC Deviation times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C. An Energy Storage Resource Model Participant or a Hybrid Resource instructed to increase charging at the request of the Office of the

Interconnection due to a transmission constraint or other reliability issue, shall be compensated for the increase in charging in the same manner as provided in sections 3.2.3(e). A unit in the Energy Storage Resource Participation Model or a Hybrid Resource instructed to reduce charging at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, is not eligible for compensation under section 3.2.3(f-4).

(f-5) If a Market Participant of an Energy Storage Resource Model Participant or a Hybrid Resource believes that the above calculations in this section 3.2.3 do not accurately compensate the Market Participant for opportunity costs associated with following PJM manual dispatch instructions to modify a unit's charging or discharging due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Participant will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Participant. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Participant accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-6) (i) A Market Seller of a pool-scheduled resource or a dispatchable self-scheduled resource shall receive Dispatch Differential Lost Opportunity Cost credits as calculated under subsection (iv) below if the resource is dispatched to provide energy in the Real-time Energy Market, provided such resource is not committed to provide real-time ancillary services (Regulation, reserves, reactive service) or instructed to reduce or suspend output due to a transmission constraint or other reliability issue pursuant to Operating Agreement, Schedule 1, section 3.2.3(f-1) through Operating Agreement, Schedule 1, section (f-4).

(ii) PJM will calculate the revenue above cost for the pricing run for each Real-time Settlement Interval in accordance with the following equation:

(A x B) - C

Where:

A = the resource's expected output level based on its resource parameters at the Real-time Price at the applicable pricing point;

B = the Real-time Price at the applicable pricing point; and

C = the sum of the resource's Real-time Energy Market offer integrated under the Final Offer for the resource's expected output level based on its resource parameters at the Real-time Price at the applicable pricing point.

(iii) PJM will calculate the revenue above cost for the dispatch run for each Real-time Settlement Interval in accordance with the following equation:

(greater of A and B) – (lesser of C and D)

Where:

A = the product of the amount of megawatts of energy dispatched in the Real-time Energy Market dispatch run for the resource in that Real-time Settlement Interval and the Real-time Price at the applicable pricing point;

B = the product of the amount of megawatts of energy the resource actually provided in that Real-time Settlement Interval and the Real-time Price at the applicable pricing point;

C = the resource's Real-time Energy Market offer integrated under the Final Offer for the amount of megawatts dispatched in the Real-time Energy Market dispatch run;

D = the resource's Real-time Energy Market offer integrated under the Final Offer for the amount of megawatts the resource actually provided in that Real-time Settlement Interval.

(iv) The Dispatch Differential Lost Opportunity Cost credit shall equal the greater of (A) the difference between the revenue above cost based on the pricing run determined in subsection (f-6)(ii) and the revenue above cost based on the dispatch run determined in subsection (f-6)(iii) or (B) zero.

(v) For each hour in an Operating Day, the total cost of the Dispatch Differential Lost Opportunity Cost credits shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load ((a) net of operating Behind The Meter Generation, but not to be less than zero; and (b) excluding Direct Charging Energy) in the PJM Region, served under Network Transmission Service, in megawatt-hours; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Operating Agreement, Schedule 1, section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(g) The sum of the foregoing credits in Operating Agreement, Schedule 1, section 3.2.3(f-1) through Operating Agreement, Schedule 1, section 3.2.3(f-54), plus any cancellation fees paid in accordance with Operating Agreement, Schedule 1, section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, plus any balancing Energy Make Whole Credits paid to pool-scheduled import transactions, less any payments received from another Control Area for Operating Reservesenergy uplift shall be allocated to each Market Participant's pro rata share of the daily total of hourly deviations in the RTO region, determined pursuant to Operating Agreement, Schedule 1, section 3.2.3(h)the cost of Operating Reserves for the Real-time Energy Market in each Operating Day. If the Office of the Interconnection declares a Market Suspension, per

Operating Agreement, Schedule 1, section 1.11.6, the Office of the Interconnection shall allocate the charges to the pro rata share of the sum of its (i) deliveries of energy to load ((a) net of operating Behind The Meter Generation, but not to be less than zero; and (b) excluding Direct Charging Energy) in the PJM Region, served under Network Transmission Service, in megawatt-hours; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Operating Agreement, Schedule 1, section 1.12.

(h) ~~The cost of Operating Reserves for the Real-time Energy Market for each Operating Day, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Tariff, Schedule 6A, shall be allocated and charged to e~~Each Market Participant's ~~based on their~~ daily total of hourly deviations are determined in accordance with the following equation:

$\sum_h (A + B + C)$

Where:

h = the hours in the applicable Operating Day;

A = For each Real-time Settlement Interval in an hour, the sum of the absolute value of the withdrawal deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy withdrawals (net of operating Behind The Meter Generation) in the Real-Time Energy Market, except as noted in subsection (h)(ii) below and in the PJM Manuals divided by the number of Real-time Settlement Intervals for that hour. The summation of each Real-time Settlement Interval's withdrawal deviation in an hour will be the Market Participant's total hourly withdrawal deviations. Market Participant bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Operating Agreement, Schedule 1, section 1.12 are not included in the determination of withdrawal deviations;

B = For each Real-time Settlement Interval in an hour, the sum of the absolute value of generation deviations (in MW and not including deviations in Behind The Meter Generation) as determined in subsection (o) divided by the number of Real-Time Settlement Intervals for that hour;

C = For each Real-time Settlement Interval in an hour, the sum of the absolute value of the injection deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy injections in the Real-Time Energy Market divided by the number of Real-time Settlement Intervals for that hour. The summation of the injection deviations for each Real-time Settlement Interval in an hour will be the Market Participant's total hourly injection deviations. The determination of injection deviations does not include generation resources.

The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Operating Agreement, Schedule 1, section 3.1A shall be used in determining the

real-time withdrawal deviations, generation deviations and injection deviations ~~used to calculate Operating Reserve~~ under this subsection (he).

~~The costs associated with scheduling of units for Black Start service or testing of Black Start Units shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Tariff, Schedule 6A.~~
The foregoing notwithstanding, netting deviations shall be allowed for each Real-time Settlement Interval in accordance with the following provisions:

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions, which include the components referenced in Operating Agreement, Schedule 1, section 3.2.3(d) regarding the cost of Energy Make Whole credits in the Day-ahead Energy Market, at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

(iv) Bilateral transactions inside the PJM Region, as defined in Operating Agreement, Schedule 1, section 1.7.10, will not be included in the determination of supply or demand deviations.

Deviations as calculated above shall be deviations in the RTO region and shall be subject to charges for the RTO region determined in accordance with Operating Agreement, Schedule 1, section 3.2.3(q)(iii). Furthermore, d~~D~~eviations that occur within a single Zone shall be associated with the Eastern or Western ~~R~~region, as defined in Operating Agreement, Schedule 1, section 3.2.3(q) below, and shall be subject to charges determined for such~~the~~ region~~al balancing Operating Reserve rate determined~~ in accordance with Operating Agreement, Schedule 1, section 3.2.3(q)(iii). Deviations at a hub shall be associated with the Eastern or Western ~~R~~region if all the buses that define the hub are located in the region. Deviations at an Interface Pricing Point shall be associated with whichever region, the Eastern or Western ~~R~~region, with which the majority of the buses that define that Interface Pricing Point are most closely electrically associated. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to charges determined for such region in accordance with Operating Agreement, Schedule 1, section 3.2.3(q)(iii)~~the regional balancing Operating Reserve rate~~. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by buses that are wholly contained within the same Zone.

~~The foregoing notwithstanding, netting deviations shall be allowed for each Real-time Settlement Interval in accordance with the following provisions:~~

~~(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.~~

~~(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions, which include the components referenced in section 3.2.3(d) regarding the cost of Operating Reserves in the Day-ahead Energy Market, at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.~~

~~(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.~~

~~(iv) Bilateral transactions inside the PJM Region, as defined in Operating Agreement, Schedule 1, section 1.7.10, will not be included in the determination of Supply or Demand deviations.~~

(i) At the end of each Operating Day, Market Sellers shall be credited for Condense Startup Cost and Condense Energy Use times the real-time LMP for synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in section 3.2.3(i) shall be the cost of ~~Operating Reserves~~energy uplift for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for the PJM Region.

(k) The cost of ~~Operating Reserves~~energy uplift for synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load ((a) net of operating Behind The Meter Generation, but not to be less than zero; and (b) excluding Direct Charging Energy) in the PJM Region, served under Network Transmission

Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Operating Agreement, Schedule 1, section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared ("Maximum Generation Emergency Alert"); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the ~~Operating Reserves~~Energy Make Whole credit otherwise provided by section 3.2.3.(b) or section 3.2.3(e-2) in connection with market-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as "MaxGen Conditions"). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Operating Agreement, Schedule 2, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Operating Agreement, Schedule 1, section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Operating Agreement, Schedule 1, section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Operating Agreement, Schedule 1, section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh and greater than the Market Seller's lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for ~~Operating Reserves~~Energy Make Whole. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for ~~Operating Reserves~~Energy Make Whole for such Operating Day pursuant to section 3.2.3(e) plus the Real-time Energy Market revenues for the Real-time Settlement Intervals that the offer is economic divided by the megawatt hours of energy provided during the Real-time Settlement Intervals that the offer is economic. The Real-time Settlement Intervals that the offer is economic shall be: (i) the Real-time Settlement Intervals that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the Real-time Settlement Intervals in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any Real-time Settlement Intervals required due to the M~~m~~inimum R~~r~~un T~~t~~ime or other operating constraint of the unit, and (iii) for any unit with a M~~m~~inimum R~~r~~un T~~t~~ime of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price for a market-based offer is greater than $1,000/MWh and greater than the Market Seller's lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for ~~Operating Reserves~~Energy Make Whole. If notice of a MaxGen Condition is provided after 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Energy Make Whole~~Operating Reserves~~ determined in accordance with section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Energy Make Whole~~Operating Reserves~~ determined in accordance with section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Energy Make Whole ~~Operating Reserves~~ for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Energy Make Whole ~~Operating Reserves~~ for such Operating Day pursuant to section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Energy Make Whole ~~Operating Reserves~~ payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) ~~Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled~~All generation resources ~~that do not follow dispatch~~ shall be assessed ~~balancing Operating Reserve~~ deviations in accordance with the calculations described below and in the PJM Manuals.

~~The Office of the Interconnection shall calculate a ramp-limited desired MW value for generation resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:~~

~~(i) real-time economic minimum <= 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.~~

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

$$Ramp_Request_t = (Dispatchtarget_{t-1} - AOutput_{t-1}) / (LAtime_{t-1})$$

$$RL_Desired_t = AOutput_{t-1} + (Ramp_Request_t * Case_Eff_time_{t-1})$$

where:

1. Dispatchtarget = Dispatch Signal for the previous approved Dispatch case
2. AOutput = Unit's achievable target MW at case solution time as defined in the PJM Manuals
3. LAtime = Dispatch look ahead time
4. Case_Eff_time = Time between signal changes
5. RL_Desired = Ramp-limited desired MW

To determine if a generation resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the dispatch signal or the actual output and ramp-limited desired MW value for each Real-time Settlement Interval. If the dispatch signal and the ramp-limited desired MW for the resource are unavailable, the Office of the Interconnection will determine the unit's MW off dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the dispatch LMP Desired MW for each Real-time Settlement Interval.

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and dispatch signal, or if its % off dispatch is <= 10, or its Real-time Settlement Interval MWh is within 5% of the Real-time Settlement Interval ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined for each Real-time Settlement Interval in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – Day-Ahead MWh.

- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – dispatch LMP Desired MW.

~~• Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – Ramp-Limited Desired MW.~~

~~• If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and dispatch LMP Desired MWh for the Real-time Settlement Interval is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: Real time Settlement Interval MWh – dispatch LMP Desired MWh.~~

~~• If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh – Ramp-Limited Desired MW. If deviation value is within 5% of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.~~

~~• If a resource is not following dispatch and its % off Dispatch is > 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh – dispatch LMP Desired MWh.~~

~~• If a resource is not following dispatch, and the resource has tripped, for the Real-time Settlement Interval the resource tripped and the Real-time Settlement Intervals it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh – Day-ahead MWh.~~

~~• For resources that are not dispatchable in both the Day-ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh - Day-Ahead MWh.~~

Generation resource deviations are calculated as the difference between a resource's Actual MWh, (which for purposes of this section is defined as the Revenue Data for Settlements), and Tracking Ramp Limited Desired MWh for each Real-time Settlement Interval except for the scenarios where day-ahead scheduled MWh are used in the calculation as defined below.

A generation resource shall not be assessed deviations for the Real-time Settlement Interval if its deviation percentage <= 0.10 (10 percent).

$$Deviation\ Percentage = Abs\left[1 - \frac{Actual\ MWh}{Tracking\ Ramp\ Limited\ Desired\ MWh}\right]$$

If the Actual MWh is equal to zero, the deviation percentage is equal to 1 (100 percent).

Generation resource deviations are calculated as the difference between a resource's Real-time Settlement Interval MWh and day-ahead scheduled MWh, rather than Tracking Ramp Limited

Desired MWh, when a resource is non-dispatchable for any Real-time Settlement Interval. For purposes of this provision, a resource will be considered non-dispatchable when any of the following conditions occur:

- The generation resource is not dispatchable in the Day-ahead Energy Market and is not dispatchable in the Real-time Energy Market. For purposes of the generation resource deviation calculation, not dispatchable is defined as intervals when the minimum operating limit is equal to the maximum operating limit, or intervals when a generation resource elects to provide a fixed output using the fixed generation parameter, or other not dispatchable processes as defined in the PJM Manuals. All hydro resources are considered non-dispatchable unless operated as a dispatchable resource by the Office of the Interconnection.
- The self-scheduled generation resource is not dispatchable due to a limited dispatchable range. A dispatchable range is considered limited when the following equation is true:
    - Abs(maximum operating limit – minimum operating limit) <= 10% of Abs(minimum operating limit).
- The dispatchable self-scheduled generation resource has a Tracking Ramp Limited Desired MWh <= the minimum operating limit, except when the resource is desired at that level due to a Minimum Generation Emergency declaration or event.
- A generation resource is online and Tracking Ramp Limited Desired MWh is unable to be calculated due to unavailable schedules or offer parameters.

A generation resource shall not be assessed deviations for the Real-time Settlement Interval if its day-ahead deviation percentage is <= 0.05 (5%).

$$Day-ahead\ Deviation\ Percentage = Abs\left[1 - \frac{Actual\ MWh}{Day-ahead\ Scheduled\ MWh}\right]$$

If the Actual MWh is equal to zero, the day-ahead deviation percentage is equal to 1 (100 percent).

A generation resource shall not be assessed deviations in a Real-time Settlement Interval if any of the following conditions occur for that interval:

- The resource is assigned pool-scheduled Regulation.
- The resource is assigned pool-scheduled Real-time Synchronized Reserves as a synchronous condenser.
- The resource is assigned pool-scheduled Real-time Secondary Reserves as a synchronous condenser.
- The resource is assigned pool-scheduled Real-time Non-Synchronized Reserves.
- The resource is assigned Real-time Synchronized Reserves and responded during a Synchronized Reserve Event.
- Flexible Resources that are committed in the Day-ahead Energy Market and not committed by the Office of the Interconnection in the Real-time Energy Market and the resource is offline.
- The resource is manually dispatched by the Office of the Interconnection and the manual instruction is not reflected in the Tracking Ramp Limited Desired MWh.

Deviations of generation resources with multiple units located at a single bus shall be netted for each Real-time Settlements Interval as described in Operating Agreement, Schedule 1, section 3.2.3(h)(i).

If a resource has an hourly average ~~sum~~ of the absolute value of generator deviations ~~for an hour~~ that is less than 5 MWh, then the resource shall not be assessed ~~balancing Operating Reserve~~ deviations for each Real-time Settlement Interval in that hour. This calculation shall be done after netting is applied, where applicable.

For the purpose of this section 3.2.3(o), a generation resource is considered to be following dispatch if it is not assessed deviations or has a deviation equal to zero in a Real-time Settlement Interval, as determined above and prior to any netting pursuant to section 3.2.3(h)(i) or for hourly averages pursuant to this section.

(o-1) Dispatchable economic load reduction resources that follow dispatch shall not be assessed ~~balancing Operating Reserve~~ deviations. Economic Load Response Participant resources that do not follow dispatch shall be assessed ~~balancing Operating Reserve~~ deviations as described in this subsection and as further specified in the PJM Manuals.

The Desired MW quantity for such resources for each hour shall be the hourly integrated MW quantity to which the load reduction resource was dispatched for each hour (where the hourly integrated value is the average of the dispatched values as determined by the Office of the Interconnection for the resource for each hour).

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no ~~balancing Operating Reserve~~ deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the ~~balancing Operating Reserve~~ deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual reduction quantity) and charged as defined in Operating Agreement, Schedule 1, section 3.3A. For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined in Operating Agreement, Schedule 1, section 3.3A. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall apply any balancing Energy Make Whole credits determined ~~allocate the charges assessed~~ pursuant to Operating Agreement, Schedule 1, section 3.2.3(e-2~~h~~), except those associated with the scheduling of units for Black Start S~~s~~ervice or testing of Black Start Service ~~U~~units as provided in Tariff, Schedule 6A, to ~~real-time~~ deviations determined pursuant to section 3.2.3(h) ~~from day-ahead schedules~~ or real-time load ~~share~~ plus exports depending on whether the underlying balancing ~~Operating Reserve~~Energy Make Whole credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day. ~~Allocation to real-time load share under this~~

~~subsection (p) shall not apply to Direct Charging Energy. If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, section 1.11.6, the Office of the Interconnection shall allocate the charges to the ratio share of real-time load plus export transactions.~~

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing ~~Operating Reserve charges~~ Energy Make Whole credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing ~~Operating Reserve charges~~Energy Make Whole credits, identified as reliability analysis credits for deviations, shall be allocated to ~~real-time~~ deviations determined pursuant to Operating Agreement, Schedule 1, section 3.2.3(h)~~from day-ahead schedules~~.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Energy Make Whole credits, identified as reliability analysis credits for reliability, ~~Operating Reserve charges~~ shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Energy Make Whole credits shall be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(p)(i)(A) and 3.2.3(p)(i)(B) hereof~~Operating Reserve charges shall be allocated pursuant to (A) or (B) above~~.

(ii) For resources scheduled during an Operating Day, the associated balancing Energy Make Whole credits ~~Operating Reserve charges~~ shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Energy Make Whole credits, identified as real-time credits for reliability, ~~Operating Reserve charges~~ shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied ~~charges will be assessed~~ pursuant to this section only if the LMP at the resource's

bus does not meet or exceeds the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the ~~charges~~ credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (real-time credits for reliability or real-time credits for deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Operating Agreement, Schedule 1,~~Operating Agreement, Schedule 1,~~ section 3.2.3(~~ph~~)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Energy Make Whole credits, identified as real-time credits for deviations, ~~Operating Reserve charges~~ shall be allocated ~~according~~ to ~~real-time~~ deviations ~~from day-ahead schedules~~ determined pursuant to Operating Agreement, Schedule 1, section 3.2.3(h).

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in Operating Agreement, Schedule 1, sections 3.2.3(p)(i) and (p)(ii).

The costs associated with scheduling of units for Black Start Service or testing of Black Start Service units shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zonal load or non-Zonal load, as determined in accordance with the formulas contained in Tariff, Schedule 6A.

(q) (i) Balancing Energy Make Whole credits for reliability or deviations as determined in Operating Agreement, Schedule 1, section 3.2.3(p) shall be assigned to the Eastern or Western region if the credit paid to the generator is due to transmission constraints that occur on transmission system capacity equal to or less than 345kv. Balancing Energy Make Whole credits for reliability or deviations not assigned to the Eastern or Western region shall be assigned to the RTO region. ~~The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region.~~ For the purposes of this section, the Western r~~R~~egion shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, DEOK, EKPC, OVEC transmission Zones, and the Eastern r~~R~~egion shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones.

(ii) The total balancing Energy Make Whole credits for reliability in each region shall be allocated as charges to each Market Participant's pro rata share of real-time load plus export transactions in such region. For purposes of this Operating Agreement, Schedule 1, section 3.2.3(q), a Market Participant's real-time load plus export transactions shall be equal to the daily total of (i) real-time deliveries of energy to load in the relevant region ((a) net of operating Behind The Meter Generation, but not to

be less than zero; and (b) excluding Direct Charging Energy), served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) real-time deliveries of energy sales from within the PJM Region to load outside the PJM Region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Operating Agreement, Schedule 1, section 1.12.

(iii) The total balancing Energy Make Whole credits for deviations in the Eastern region and the Western region shall be allocated as charges to each Market Participant's pro rata share of the daily total of hourly deviations in the relevant region as determined pursuant to Tariff, Operating Agreement, Schedule 1, section 3.2.3(h). The total balancing Energy Make Whole credits for deviations in the RTO region plus the total credits as determined in Operating Agreement, Schedule 1, section 3.2.3(g) shall be allocated as charges to each Market Participant's pro rata share of the daily total of hourly deviations in the RTO region as determined pursuant to Operating Agreement, Schedule 1, section 3.2.3(h). If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.11.6, the Office of the Interconnection shall allocate deviation charges to the ratio share of real-time load plus export transactions pursuant to Operating Agreement, Schedule 1, section 3.2.3(q)(ii).

(q-1) (i) ~~The r~~Regional balancing ~~Operating Reserve~~uplift rates shall be determined in accordance with the following provisions:

~~(i)~~ The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western ~~R~~regions. Regional adder rates for reliability shall be equal to the total balancing ~~Operating Reserve~~Energy Make Whole credits ~~paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into~~for reliability in the region divided by the total real-time load plus export transactions in the relevant region in accordance with Operating Agreement, Schedule 1, section 3.2.3(q)(ii)~~and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively~~. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with Operating Agreement, Schedule 1, section 3.2.3(p). ~~Allocation to real-time load share under this subsection (q)(i) shall not apply to Direct Charging Energy.~~

Regional adder rates for deviations shall be equal to the total balancing Energy Make Whole credits for deviations in the region divided by the daily total of hourly deviations in the relevant region in accordance with Operating Agreement, Schedule 1, section 3.2.3(q)(iii).

(ii) The Office of the Interconnection shall calculate RTO balancing ~~Operating Reserve~~uplift rates. RTO balancing ~~Operating Reserve~~uplift rates for reliability shall be equal to the total balancing ~~Operating Reserve~~Energy Make Whole credits for reliability in the RTO region divided by the total real-time load plus export transactions in the RTO region in accordance with section (q)(ii). RTO balancing uplift

rates for deviations shall be equal to the total balancing Energy Make Whole credits for deviations in the RTO region plus the total credits as determined in Operating Agreement, Schedule 1, section 3.2.3(g) divided by the daily total of hourly deviations in the RTO region as determined pursuant to Operating Agreement, Schedule 1, section 3.2.3(h).~~except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Tariff, Schedule 6A, in excess of the regional adder rates calculated pursuant to Operating Agreement, Schedule 1, section 3.2.3(q)(i). The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively.~~ Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Operating Agreement, Schedule 1, section 3.2.3(p). ~~Allocation to real-time load share under this subsection (q)(ii) shall not apply to Direct Charging Energy.~~

(iii) Reliability and deviation regional balancing ~~Operating Reserve~~uplift rates shall be determined by summing the relevant RTO balancing ~~Operating Reserve~~Energy Make Whole rates and regional adder rates.

~~(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.~~

(r) Market Sellers that incur incremental operating costs for a generation resource that are either greater than $1,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Operating Agreement, Schedule 2 and PJM Manual 15, but are not verified at the time of dispatch of the resource under Operating Agreement, Schedule 1, section 6.4.3, or greater than $2,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Operating Agreement, Schedule 2, and PJM Manual 15, will be eligible to receive credit for ~~Operating Reserves~~Energy Make Whole upon review of the Market Monitoring Unit and the Office of the Interconnection, and approval of the Office of the Interconnection. Market Sellers must submit to the Office of the Interconnection and the Market Monitoring Unit all relevant documentation demonstrating the calculation of costs greater than $2,000/MWh, and costs greater than $1,000/MWh which were not verified at the time of dispatch of the resource under Operat~~r~~ing Agreement, Schedule 1, section 6.4.3. The Office of the Interconnection must approve any ~~Operating Reserve~~Energy Make Whole credits paid to a Market Seller under this subsection (r).

3.2.3A Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with

provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant's hourly Synchronized Reserve Obligation shall be adjusted by any Synchronized Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Synchronized Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Synchronized Reserve as defined in sections 3.2.3A(b)(i) and (ii) below.

(b) A resource supplying Synchronized Reserve at the direction of the Office of the Interconnection shall be credited as follows:

i) Credits for Synchronized Reserve provided by generation and Economic Load Response Participant resources assigned to provide Synchronized Reserve by the Office of the Interconnection or self-scheduled in the Day-ahead Synchronized Reserve Market shall be equal to the product of the Day-ahead Synchronized Reserve Market Clearing Price multiplied by the megawatt amount of Synchronized Reserve such resource is assigned to provide..

ii) Credits for Synchronized Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Synchronized Reserve by the Office of the Interconnection or self-scheduled in the Real-time Synchronized Reserve Market shall be determined for each operating hour based on the sum of their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$$\sum_i ((A - B) * C)$$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Synchronized Reserve from that resource assigned by the Office of the Interconnection or self-scheduled in the Real-time Synchronized Reserve Market. The megawatt value is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval where there is not a Synchronized Reserve event;

B = For each Real-time Settlement Interval, the megawatts of Synchronized Reserve from that resource assigned by the Office of the Interconnection or self-scheduled in the Day-ahead Synchronized Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Synchronized Reserve Market Clearing Price.

If a Synchronized Reserve Event is initiated by the Office of the Interconnection and the Economic Load Response Participant resource reduced its load in response to the event, the resource shall be eligible to receive a credit for the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

iii) Pool-scheduled resources shall be credited a Synchronized Reserve lost opportunity cost credit, where positive, as described in subsection (f)(iv) below.

(c) [Reserved for future use]

(d) Synchronized Reserve Market Clearing Prices

(i) For the Day-ahead Synchronized Reserve Market, the Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Synchronized Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for Synchronized Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Synchronized Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Synchronized Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Synchronized Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute and (B) the price of serving the next increment of demand for Primary Reserve and 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute, provided that the Synchronized Reserve Market Clearing Price shall be less than or equal to the sum of no more than two of the Reserve Penalty Factors for the Synchronized Reserve Requirement, the Primary Reserve Requirement, and the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.10.8(d), Day-ahead Synchronized Reserve Market Clearing Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and Day-ahead Synchronized Reserve Market Clearing Price of zero dollars per megawatt-hour and all settlements will be based on the Real-time Synchronized Reserve market quantities and prices as determined pursuant to subsection (d)(ii) hereof.

(ii) For the Real-time Synchronized Reserve Market, the Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving

the next increment of demand for Synchronized Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Synchronized Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Synchronized Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Synchronized Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute and (B) the price of serving the next increment of demand for Primary Reserve and 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute, provided that the Synchronized Reserve Market Clearing Price shall be less than or equal to the sum of no more than two of the Reserve Penalty Factors for the Synchronized Reserve Requirement, the Primary Reserve Requirement, and the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, and the Office of the Interconnection is not assigning Synchronized Reserves, then the Synchronized Reserve Market Clearing Price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, where the real-time Market Suspension is less than or equal to six (6) consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Synchronized Reserves, then the Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Synchronized Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than six (6) consecutive hours but less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating Days, and there are cleared Day-ahead Synchronized Reserve Market Clearing Prices for the affected Operating Day, then the Real-time Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the Day-ahead Synchronized Reserve Market Clearing Prices for each corresponding hour. If no such Day-ahead Synchronized Reserve Market Clearing Prices exist, then the Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Synchronized Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than twenty-four (24) consecutive hours, and the Office of the Interconnection is assigning Synchronized Reserves, the Office of the Interconnection will set the Synchronized Reserve Market Clearing Price to zero

dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period. Resources will be compensated for lost opportunity cost per subsection (f) hereof using the energy price as determined in Operating Agreement, Schedule 1, section 2.5.2.iii. The opportunity cost shall be zero for all resources self-scheduled to provide Synchronized Reserve, synchronous condensers and Economic Load Response Participant resources.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Synchronized Reserve Market Clearing Price shall be the sum of the Reserve Penalty Factors for the Primary Reserve Requirement, and the Synchronized Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

(iii) The Reserve Penalty Factor for the Synchronized Reserve Requirement shall be $850/MWh.

The Reserve Penalty Factor for the Extended Synchronized Reserve Requirement shall be $300/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Synchronized Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(e) (i) For determining the Synchronized Reserve Market Clearing Price in each hour of the Day-ahead Synchronized Reserve Market, the estimated resource-specific opportunity cost for a generation resource or Economic Load Response Participant resource shall be the difference between the Locational Marginal Price at the generation or Economic Load Response Participant resource bus and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) or offer price to reduce energy from the Economic Load Response Participant resource in the PJM Interchange Energy Market when the Locational Marginal Price at the generation or Economic Load Participant resource bus is greater than the offer price for energy from the generation resource or the offer price to reduce energy from the Economic Load Response Participant resource.

However, the opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve and for synchronous condensers and for Economic Load Response Participant resources that do not receive a day-ahead commitment to provide energy in the same operating hour in which such resource is committed to provide Synchronized Reserve.

(ii) For determining the Synchronized Reserve Market Clearing Price for each Real-time Settlement Interval in the Real-time Synchronized Reserve Market, the

estimated unit-specific opportunity cost for a generation resource that is not a hydroelectric resource shall be the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

For hydroelectric resources, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions, as defined in the PJM Manuals, and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

The opportunity costs shall be zero for all resources self-scheduled to provide Synchronized Reserve, synchronous condensers and Economic Load Response Participant resources.

(f) (i) In determining the credit under subsection (b) to a generation resource, except a generation resource that is operating as a synchronous condenser, selected to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market, or an Economic Load Response Participant resource that is selected to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market for the same operating hour in which such resource receives a day-ahead commitment to provide energy, the opportunity cost of a resource shall be determined for each operating hour that the Office of the Interconnection requires a resource to provide Synchronized Reserve and shall be in accordance with the following equation:

(A x B) - C

Where:

A = The Day-ahead Locational Marginal Price at the generation bus of the generation resource or the applicable pricing point for the Economic Load Response Participant resource;

B = The deviation of the resource's energy output or load reduction necessary to supply a Day-ahead Synchronized Reserve assignment from the resource's energy expected output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load; and

C = The Day-ahead Energy market offer integrated under the applicable energy offer curve for the resource's energy output or load reduction necessary to provide a Day-ahead Synchronized Reserve Market assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load.

For a generation resource that is operating as a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [Condense Energy Use multiplied by A] plus [the applicable Condense Startup Cost divided by the number of hours the resource is assigned Synchronized Reserve].

(ii) In determining the credit under subsection (b) to a generation resource, except a generation resource that is operating as a synchronous condenser, selected to provide Synchronized Reserve in the Real-time Synchronized Reserve Market in excess of the resource's Day-ahead Synchronized Reserve Market assignment and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of that generation resource shall be determined for each Real-time Settlement Interval that the Office of the Interconnection requires that generation resource to provide Synchronized Reserve and shall be in accordance with the following equation:

(A x B) - C

Where:

A = The Real-time Locational Marginal Price at the generation bus of the generation resource;

B = The deviation of the generation resource's output necessary to supply Synchronized Reserve in real-time, reduced by the amount of Synchronized Reserve the resource failed to respond during a Synchronized Reserve Event during the Operating Day, in excess of its Day-ahead Synchronized Reserve Market assignment and follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy; and

C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Synchronized Reserve in real-time from the lesser of the generation resource's output necessary to provide a Day-ahead Synchronized Reserve Market assignment or follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [additional Condense Energy Use in excess of day-ahead Condense Energy Use in real-time multiplied by A] plus [any

applicable Condense Startup Cost due to additional Condense Startup Cost in real-time in excess of day-ahead Condense Startup Cost allocated to each Real-time Settlement Interval as described in PJM Manuals].

For hydroelectric resources, the unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the real-time Locational Marginal Price at that generation bus multiplied by the additional megawatts assigned to supply Synchronized Reserve in real-time in excess of its Day-ahead Synchronized Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average real-time Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating multiplied by the additional megawatts assigned to supply the hourly Synchronized Reserve in real-time in excess of its Day-ahead Synchronized Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

(iii) For each Real-time Settlement Interval, a Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in the resource's real-time reserve MW from a day-ahead market assignment in more than one market for that Real-time Settlement Interval, the total Market Revenue Neutrality Offset is allocated to the Synchronized Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Synchronized Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Synchronized Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Synchronized Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Synchronized Reserve assignment decreases due to the resource being self-scheduled to provide energy or Regulation;

(B) A resource reduces its flexibility in real-time such that the resource no longer qualifies to provide Synchronized Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time;

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above; or

(F) A resource increases its Synchronized Reserve offer price in the Real-time Synchronized Reserve Market from its offer price in the Day-ahead Synchronized Reserve Market.

(iv) A Synchronized Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

(A + B + C + D) – (E + F + G + H)

Where:

A = day-ahead Synchronized Reserve offer price times the Synchronized Reserve MW assignment;

B = real-time Synchronized Reserve offer price times the Synchronized Reserve MW assigned in real-time in excess of the Synchronized Reserve MW assigned day-ahead, where the Synchronized Reserve MW assigned is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval where there is not a Synchronized Reserve event;

C = day-ahead opportunity cost as determined in subsection (f)(i) above;

D = real-time opportunity cost as determined in subsection (f)(ii) above;

E = day-ahead clearing price credits as determined in subsection (b)(i) above;

F = real-time clearing price credits as determined in subsection (b)(ii) above less any applicable charges for failure to respond to a Synchronized Reserve Event as determined in subsection (j) below;

G = the applicable Market Revenue Neutrality Offset as determined in subsection (f)(iii) above; and

H = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A(f)(iii) above if not eligible for Market Revenue Neutrality Offset.

(v) The opportunity costs for an Economic Load Response Participant resource assigned Synchronized Reserve in real-time or any resource self-scheduled for Synchronized Reserves shall be zero.

(g) [Reserved for future use]

(h) For each operating hour, the sum of the Synchronized Reserve lost opportunity cost credits credited in accordance with subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Synchronized Reserve Obligation in proportion to its real-time purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) [Reserved for future use]

(j) In the event a generation resource or Economic Load Response Participant Resource that either has been assigned by the Office of the Interconnection or self-scheduled to provide Synchronized Reserve in real-time fails to provide the amount of Synchronized Reserve it was directed to deploy in response to a Synchronized Reserve Event, the resource will be charged at the Real-time Synchronized Reserve Market Clearing Price for the real-time Synchronized Reserve the resource was directed to deploy, in excess of the amount that actually responded for all Real-time Settlement Intervals the resource was assigned or self-scheduled Synchronized Reserve real-time. For each Real-time Settlement Interval where there is not a Synchronized Reserve Event, the megawatts that will be charged shall be the lesser of the amount of the shortfall of Synchronized Reserve, measured in megawatts, or the real-time Synchronized Reserve assignment, which is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements for the resource on the Operating Day during which the event occurred. The determination of the amount of Synchronized Reserve credited to a resource shall be on an individual resource basis, not on an aggregate basis.

The resource shall refund payments received for Synchronized Reserve it failed to provide. For purposes of determining the amount of the payments to be refunded by a Market Participant, the Office of the Interconnection shall calculate the shortfall of Synchronized Reserve on an individual resource basis unless the Market Participant had multiple resources that were assigned or self-scheduled to provide Synchronized Reserve, in which case the shortfall will be determined on an aggregate basis. For performance determined on an aggregate basis, the response of any resource that was assigned or self-scheduled for Synchronized Reserve and provided more Synchronized Reserve than it was directed to deploy will be used to offset the performance of other resources that provided less assigned or self-scheduled Synchronized Reserve than they were directed to deploy during a Synchronized Reserve Event, as calculated in the PJM Manuals. The determination of a Market Participant's aggregate response shall not be taken into consideration in the determination of the amount of Synchronized Reserve credited to each individual resource.

The amount refunded shall be determined by multiplying the retroactive penalty megawatts by the Real-time Synchronized Reserve Market Clearing Price for all intervals the resource was

assigned or self-scheduled to provide Synchronized Reserve for a period of time immediately preceding the Synchronized Reserve Event equal to the lesser of the average number of days between Synchronized Reserve Events, or the number of days since the resource last failed to provide the amount of Synchronized Reserve it was directed to deploy in response to a Synchronized Reserve Event. The retroactive penalty megawatts for each interval shall be the lesser of the amount of the shortfall of Synchronized Reserve, measured in megawatts, and the real-time Synchronized Reserve assignment for each interval, which is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements for the resource. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following January 1. The refunded charges shall be allocated as credits to Market Participants based on its pro rata share of the Synchronized Reserve Obligation megawatts in the hour(s) of the Synchronized Reserve Event for the Reserve Sub-zone or Reserve Zone, except that Market Participants that incur a refund obligation and also have an applicable Synchronized Reserve Obligation during the hour(s) of the Synchronized Reserve Event shall not be included in the allocation of such refund credits. If the event spans multiple hours, the refund credits will be prorated hourly based on the duration of the event within each clock hour.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or an Economic Load Response Participant resource, except for Batch Load Economic Load Response Participant resources covered by section 3.2.3A(l), is the difference between the generation resource's output or the Economic Load Response Participant resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Economic Load Response Participant resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Economic Load Response Participant resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or an Economic Load Response Participant resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Economic Load Response Participant resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to an Economic Load Response Participant resource will be reduced by the amount the megawatt consumption of the Economic Load Response Participant resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Economic Load Response Participant resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the

difference between (i) the Batch Load Economic Load Response Participant resource's consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Economic Load Response Participant resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Economic Load Response Participant resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant's hourly Non-Synchronized Reserve Obligation shall be adjusted by any Non-Synchronized Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Non-Synchronized Reserve Obligation shall be charged the pro rata share of the sum day-ahead and real-time credits for Non-Synchronized Reserve as defined in sections 3.2.3A.001(b)(i) and (ii) below.

(b) Resources assigned to provide Non-Synchronized Reserve at the direction of the Office of the Interconnection shall be credited as follows:

(i) Credits for Non-Synchronized Reserve provided by generation resources assigned to provide Non-Synchronized Reserve by the Office of the Interconnection in the Day-ahead Non-Synchronized Reserve Market shall be equal to the product of the Day-ahead Non-Synchronized Market Clearing Price multiplied by the megawatt amount of Non-Synchronized Reserve such resource is assigned to provide.

(ii) Credits for Non-Synchronized Reserve provided by generation resources assigned to provide Non-Synchronized Reserve by the Office of the Interconnection in the Real-time Non-Synchronized Reserve Market shall be determined for each operating hour based on the sum on their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$$\sum_i ((A - B) * C)$$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Non-Synchronized Reserve from that resource assigned by the Office of the Interconnection in the Real-time Non-Synchronized Reserve Market;

B = For each Real-time Settlement Interval, the megawatts of Non-Synchronized Reserve from that resource assigned by the Office of the Interconnection in the Day-ahead Non-Synchronized Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Non-Synchronized Reserve Market Clearing Price.

(iii) Pool-scheduled generation resources assigned to provide Non-Synchronized Reserve in the Day-ahead Non-Synchronized Reserve Market shall be credited a Non-Synchronized Reserve lost opportunity cost credit, where positive, as determined in accordance with subsection (d)(iii) below, to recover any net monetary loss to the Market Seller of such resource associated with the purchase of Non-Synchronized Reserve in the Real-time Non-Synchronized Reserve Market as a result of following the dispatch direction of the Office of the Interconnection.

(c) Non-Synchronized Reserve Market Clearing Prices

(i) For the Day-ahead Non-Synchronized Reserve Market, the Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Non-Synchronized Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for Primary Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Non-Synchronized Reserve offer prices and the applicable Operating Reserve Demand Curve for Non-Synchronized Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Primary Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute and (B) the price of serving the next increment of demand for 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute, provided that the Non-Synchronized Reserve Market Clearing Price shall be less than or equal to the product of 1.5 multiplied by the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Non-Synchronized Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.10.8(d), Day-ahead Non-Synchronized Reserve Market Clearing Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and Day-ahead Non-Synchronized Reserve Market

Clearing Price of zero dollars per megawatt-hour and all settlements will be based on the Real-time Non-Synchronized Reserve market quantities and prices as determined pursuant to subsection (c)(ii) hereof.

(ii) For the Real-time Non-Synchronized Reserve Market, the Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for Primary Reserve in a Reserve Zone or Reserve Sub-zone determined by the interaction between a supply curve formed using Non-Synchronized Reserve offer prices and the applicable Operating Reserve Demand Curve for Non-Synchronized Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Primary Reserve for any other Reserve Zone or Reserve Subzone to which the next increment of demand for Primary Reserve can contribute and (B) the price of serving the next increment of demand for 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute, provided that the Non-Synchronized Reserve Market Clearing Price shall be less than or equal to the product of 1.5 multiplied by the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Non-Synchronized Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, and the Office of the Interconnection is not assigning Non-Synchronized Reserves, then the Non-Synchronized Reserve Clearing Price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, where the real-time Market Suspension is less than or equal to six (6) consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Non-Synchronized Reserves, then the Non-Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Non-Synchronized Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than six (6) consecutive hours but less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating Days, and there are cleared Day-ahead Non-Synchronized Reserve Market Clearing Prices for the affected Operating Day, then the Real-time Non-Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the Day-ahead Non-Synchronized Reserve Market Clearing Prices for each corresponding hour. If no

such Day-ahead Non-Synchronized Reserve Market Clearing Prices exist, then the Non-Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Non-Synchronized Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than twenty-four (24) consecutive hours, the Non-Synchronized Reserve Market Clearing Price will be set to zero dollars per megawatt-hour regardless of whether the Office of the Interconnection is assigning Non-Synchronized Reserves.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Non-Synchronized Reserve Market Clearing Price shall be the product of 1.5 multipled by the Reserve Penalty Factor for the Primary Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

(iii) The Reserve Penalty Factor for the Primary Reserve Requirement shall be $850/MWh.

The Reserve Penalty Factor for the Extended Primary Reserve Requirement shall be $300/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Primary Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(d) (i) For determining the Non-Synchronized Reserve clearing price for each hour in the Day-ahead Non- Synchronized Reserve Market and for each Real-time Settlement Interval in the Real-time Non-Synchronized Reserve Market, including during a declaration of a Market Suspension, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves will be zero.

(ii) For each Real-time Settlement Interval, a total Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in real-time reserve MW from a day-ahead market assignment in more than one market for that Real-time Settlement Interval, the total Market Revenue Neutrality Offset is allocated to the Non-Synchronized Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Non-Synchronized Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Non-Synchronized Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Non-Synchronized Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Non-Synchronized Reserve assignment decreases due to the resource being self-scheduled to provide energy, Synchronized Reserve, or Regulation;

(B) A resource reduces flexibility in real-time such that the resource no longer qualifies to provide Non-Synchronized Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time; or

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above.

(iii) A Non-Synchronized Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

(zero) – (A + B + C + D)

Where:

A = day-ahead clearing price credits as determined in subsection (b)(i) above;

B = real-time clearing price credits as determined in subsection (b)(ii) above;

C = the applicable Market Revenue Neutrality Offset as determined in subsection (d)(ii) above; and

D = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A.001(d)(ii) above if not eligible for Market Revenue Neutrality Offset.

(e) [Reserved for future use]

(f) For each operating hour, the sum of the Non-Synchronized Reserve lost opportunity cost credits credited in subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation in

proportion to its real-time purchases of Non-Synchronized Reserve in megawatt-hours during that hour.

(g) The magnitude of response to a Non-Synchronized Reserve Event by a generation resource is the difference between the generation resource's output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output at the start of the event is defined as the lowest telemetered generator resource output between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output 10 minutes after the start of the event is defined as the greatest generator resource output achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(h) In the event a generation resource that has been assigned by the Office of the Interconnection to provide Non-Synchronized Reserve fails to provide the assigned amount of Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the contiguous Real-time Settlement Interval the resource was assigned Non-Synchronized Reserve during which the event occurred.

3.2.3A.01 Secondary Reserve.

(a) Each Market Participant that is a Load Serving Entity shall have an obligation for hourly Secondary Reserve equal to its pro rata share of Secondary Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Secondary Reserve Obligation"). A Market Participant's hourly Secondary Reserve Obligation shall be adjusted by any Secondary Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Secondary Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Secondary Reserve as defined in sections 3.2.3A.01(b)(i) and (ii) below.

(b) Resources assigned to provide Secondary Reserve at the direction of the Office of the Interconnection shall be credited as follows:

(i) Credits for Secondary Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Secondary Reserve by the Office of the Interconnection in the Day-ahead Secondary Reserve Market shall be equal to the product of the Day-ahead Secondary Reserve Market Clearing Price multiplied by the megawatt amount of Secondary Reserve such resource is scheduled to provide.

(ii) Credits for Secondary Reserve provided by generation resources and Economic Load Response Participant resources scheduled to provide Secondary Reserve by the Office of the Interconnection in the Real-time Secondary Reserve Market shall be determined for each operating hour based on the sum of their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$\sum_i ((A - B) * C)$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Secondary Reserve from that resource assigned by the Office of the Interconnection in the Real-time Secondary Reserve Market. The megawatt value is capped at the lesser of the Economic Maximum or Secondary Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval minus the Real-time Synchronized Reserve assignment;

B = For each Real-time Settlement Interval, the megawatts of Secondary Reserve from that resource scheduled by the Office of the Interconnection in the Day-ahead Secondary Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Secondary Reserve Market Clearing Price.

(iii) Pool-scheduled resources and Economic Load Response Participant resources shall be credited a Secondary Reserve lost opportunity cost credit, where positive, as described in subsection (f)(iv) below.

(c) [Reserved for future use]

(d) Secondary Reserve Market Clearing Prices

(i) For the Day-ahead Secondary Reserve Market, the Secondary Reserve Market Clearing Price shall be determined for each Reserve Zone and, as applicable, Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Secondary Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for 30-minute Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Secondary Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Secondary Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus the price of serving the next increment of demand for 30-minute Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute, but the Secondary Reserve Market Clearing Price shall

not exceed the Reserve Penalty Factor for the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.10.8(d), Day-ahead Secondary Reserve Market Clearing Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and Day-ahead Secondary Reserve Market Clearing Price of zero dollars per megawatt-hour and all settlements will be based on the Real-time Secondary Reserve market quantities and prices as determined pursuant to subsection (d)(ii) hereof.

(ii) For the Real-time Secondary Reserve Market, the Secondary Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for 30-minute Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Secondary Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Secondary Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus the price of serving the next increment of demand for 30-minute Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute but the Secondary Reserve Market Clearing Price shall not exceed the Reserve Penalty Factor for the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, and the Office of the Interconnection is not assigning Secondary Reserves, then the Secondary Reserve Clearing Price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, where the real-time Market Suspension is less than or equal to six (6) consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Secondary Reserves, then the Secondary Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Secondary Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than six (6) consecutive hours but less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating

Days, and there are cleared Day-ahead Secondary Reserve Market Clearing Prices for the affected Operating Day, then the Real-time Secondary Reserve Market Clearing Prices associated with such Market Suspension shall be the Day-ahead Secondary Reserve Market Clearing Prices for each corresponding hour. If no such Day-ahead Secondary Reserve Market Clearing Prices exist, then the Secondary Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Secondary Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than twenty-four (24) consecutive hours, and the Office of the Interconnection is assigning Secondary Reserves, the Secondary Reserve Market Clearing Price will be set to zero dollars per megawatt-hour. Resources will be compensated for lost opportunity cost per subsection (f) hereof using the energy price as determined in Operating Agreement, Schedule 1, section 2.5.2.iii.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Secondary Reserve Market Clearing Price for a given Reserve Zone or Sub-zone shall be the Reserve Penalty Factor for the 30-minute Reserve Requirements for that Reserve Zone or Reserve Sub-zone .

(iii) The Reserve Penalty Factor for the 30-minute Reserve Requirement shall be $850/MWh.

The Reserve Penalty Factor for the Extended 30-minute Reserve Requirement shall be $300/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Reserve Penalty Factor for 30-minute Reserve are warranted for subsequent Delivery Year(s).

(e) (i) For determining the Secondary Reserve Market Clearing Price for each hour in the Day-ahead Secondary Reserve Market, the estimated resource-specific opportunity cost for a generation resource or Economic Load Response Participant resources shall be the difference between the Locational Marginal Price at the generation or Economic Load Response Participant resource bus and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) or offer price to reduce energy from the Economic Load Response Participant resource in the PJM Interchange Energy Market when the Locational Marginal Price at the Economic Load Response Participant resource bus is greater than the offer price for energy from the generation resource or the offer price to reduce energy from the Economic Load Response Participant resource.

However, opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve, and for synchronous condensers and for Economic Load

Response Participant resources that do not receive a day-ahead commitment to provide energy in the same operating hour in which such resource is committed to provide Secondary Reserve.

(ii) For determining the Secondary Reserve Market Clearing Price for each Real-time Settlement Interval in the Real-time Secondary Reserve Market, the estimated unit-specific opportunity cost for a generation resource that is not a hydroelectric resource shall be the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

For hydroelectric resources, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

However, the opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve, and for synchronous condensers and Economic Load Response Participant resources.

(f) (i) In determining the credit under subsection (b) to a generation resource, except a generation resource that is a synchronous condenser, selected to provide Secondary Reserve in the Day-ahead Secondary Reserve Market or an Economic Load Response Participant resource that is selected to provide Secondary Reserve in the Day-ahead Secondary Reserve Market in the same operating hour in which such resource receives a day-ahead commitment to provide energy, the opportunity cost of a resource shall be determined for each operating hour that the Office of the Interconnection requires a resource to provide Secondary Reserve and shall be in accordance with the following equation:

(A x B) – C

Where:

A = The Day-ahead Locational Marginal Price at the generation bus of the generation resource or the applicable pricing point for the Economic Load Response Participant resource;

B= The deviation of the resource's energy output or load reduction necessary to supply a Day-ahead Secondary Reserve assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load less any Day-ahead Synchronized Reserve Market assignment; and

C = The Day-ahead Energy Market offer integrated under the applicable energy offer curve for the resource's energy output or load reduction necessary to provide a Day-ahead Secondary Reserve Market assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load less any Day-ahead Synchronized Reserve Market assignment.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [Condense Energy Use multiplied by A] plus [the applicable Condense Startup Cost divided by the number of hours the resource is assigned Secondary Reserve].

(ii) In determining the credit under subsection (b) to a generation resource, except a generation that is a synchronous condenser, selected to provide Secondary Reserve in the Real-time Secondary Reserve Market in excess of the resource's Day-ahead Secondary Reserve Market assignment and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of that generation resource shall be determined for each Real-time Settlement Interval that the Office of the Interconnection requires that generation resource to provide Secondary Reserve and shall be in accordance with the following equation:

(A x B) – C

Where:

A = The Real-time Locational Marginal Price at the generation bus of the generation resource;

B= The deviation of the generation resource's output necessary to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment and follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy less any Real-time Synchronized Reserve Market assignment; and

C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Secondary Reserve in real-time from the lesser of the generation resource's output necessary to provide a Day-ahead Secondary Reserve Market assignment or follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy less any Real-time Synchronized Reserve Market assignment.

For hydroelectric resources, the unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the real-time Locational Marginal Price at that generation bus multiplied by the additional megawatts assigned to supply Synchronized Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average real-time Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating multiplied by the additional megawatts assigned to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: additional Condense Energy Use in excess of day-ahead Condense Energy Use multiplied by A plus [any applicable Condense Startup Cost due to additional Condense Startup Cost in real-time in excess of day-ahead Condense Startup Cost allocated to each Real-time Settlement Interval as described in PJM Manuals]. If the generation resource is operating as a synchronous condenser and also has a Real-time Synchronized Reserve assignment, resource's unit-specific opportunity cost in the Secondary Reserve Market shall be zero.

(iii) For each Real-time Settlement Interval, a total Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in real-time reserve MW from a day-ahead market assignment in more than one market for that real-time settlement interval, the total Market Revenue Neutrality Offset is allocated to the Secondary Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Secondary Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Secondary Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Secondary Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Secondary Reserve assignment decreases due to the resource being self-scheduled to provide energy, Synchronized Reserve, or Regulation;

(B) A resource reduces flexibility in real-time such that the resource no longer qualifies to provide Secondary Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time;

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above; or

(F) A resource that fails to come online and reach Economic Minimum output within 30 minutes as described in section 3.2.3A.01(h)(i) below.

(iv) A Secondary Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

(A + B) – (C + D + E + F)

Where:

A = day-ahead opportunity cost as determined in subsection (f)(i) above;

B = real-time opportunity cost as determined in subsection (f)(ii) above;

C = day-ahead clearing price credits as determined in subsection (b)(i) above;

D = real-time clearing price credits as determined subsection (b)(ii) above;

E = the applicable Market Revenue Neutrality Offset as determined in subsection (f)(iii) above; and

F = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A.01(f)(iii) above if not eligible for Market Revenue Neutrality Offset.

(v) The opportunity costs for Economic Load Response Participant resources and generation resources not synchronized to the grid shall be zero, except that Economic Load Response Participant resources may have a day-ahead opportunity cost, as determined in subsection (f)(i) above.

(g) For each operating hour, the sum of the Secondary Reserve lost opportunity cost credits credited in accordance with subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Secondary Reserve Obligation in proportion to its real-time purchases of Secondary Reserve in megawatt-hours during that hour.

(h) (i) In the event an offline generation resource has been assigned by the Office of the Interconnection to provide Secondary Reserve in real-time and is subsequently dispatched by the Office of the Interconnection to supply energy during that Operating Day and the resource qualifies as a Secondary Reserve resource at the time it is dispatched to provide energy, the Office of the Interconnection will assess the resource's performance as follows:

For each generation resource that fails to come online and reach Economic Minimum output within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval and for all prior intervals in which the resource was assigned to provide Secondary Reserve in the Real-time Secondary Reserve Market starting at the later of (A) the last interval the resource was online or (B) the beginning of that Operating Day and continuing up to the interval the resource failed to come online. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time not being paid for the assigned MW.

(ii) In the event an Economic Load Response Participant resource has been assigned by the Office of the Interconnection to provide Secondary Reserve in real-time and is subsequently dispatched to supply the Secondary Reserve assignment as a load reduction, the Office of the Interconnection will assess the resource's performance as follows:

For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between 29 and 31 minutes after the issuance of a dispatch instruction from the Office of the Interconnection.

For each Economic Load Response Participant resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described above, within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval, and for all prior intervals in which the resource was assigned to provide Secondary Reserve in

the Real-time Secondary Reserve Market between such non-performance event starting at the later of (A) the last interval the resource reduced load at the instruction of the Office of the Interconnection or (B) the beginning of that Operating Day, and for all subsequent intervals through the earlier of (C) the next interval in which the resource is dispatched to reduce load or (D) the end of the Operating Day. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time, refunding all payments due for Secondary Reserve during such period.

(iii) For Batch Load Economic Load Response Participant Resources, a second method of verification will be used for instances where a Secondary Reserve assignment dispatched as an energy load reduction is initiated and the resource is operating at the minimum consumption level of its duty cycle. In this case, the magnitude of the response will be measured as the difference between (A) the minimum of the resource's consumption between the minute before and the minute after the end of the last settlement interval the resource reduced load at the instruction of the Office of the Interconnection and (B) the maximum consumption within a ten (10) minute period following the end of the last settlement interval the resource reduced load provided that all subsequent minutes following that minute are no less than 50% of the consumption in that minute.

For each Batch Load Economic Load Response Participant Resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described in section (ii) above or the difference between (A) and (B) as described in section (iii) above, within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval, and for all prior intervals in which the resource was assigned to provide Secondary Reserve in either the Day-ahead or Real-time Secondary Reserve Markets between such non-performance event starting at the later of (A) the last interval the resource reduced load at the instruction of the Office of the Interconnection or (B) the beginning of that Operating Day, and for all subsequent intervals through the earlier of (C) the next interval in which the resource is dispatched to reduce load or (D) the end of the Operating Day. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time, refunding all payments due for Secondary Reserve during such period.

3.2.3A.02 Operating Reserve Demand Curves

The Office of the Interconnection shall establish Operating Reserve Demand Curves for clearing 30-minute Reserve, Primary Reserve, and Synchronized Reserve, for, as applicable, each Reserve Zone or Reserve Sub-zone to procure sufficient reserves to meet, as applicable, (a) 30-minute Reserve Requirement and Extended 30-minute Reserve Requirement; (b) Primary Reserve Requirement and Extended Primary Reserve Requirement; and (c) Synchronized Reserve Requirement and Extended Synchronized Reserve Requirement. The Operating Reserve Demand Curves established for each reserve type shall be used to commit such reserves in both the day-ahead and real-time reserve markets. The Operating Reserve Demand Curves

shall be determined in accordance with the applicable Reserve Penalty Factors and PJM Manuals.

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output, when positive, of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from a steam-electric generating unit, a Hybrid Resource, or a combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3(c) hereof), and where the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C. An Energy Storage Resource Model Participant or a Hybrid Resource instructed to reduce charging to provide Reactive Services is not eligible for compensation under section (c).

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3(c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost for each Real-time Settlement Interval, limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(e) At the end of each Operating Day, where the active energy output (positive generation output) of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to section 3.2.3B(f). At the end of each Operating Day, when an Energy Storage Resource Model Participant or a Hybrid Resource is instructed to increase charging at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from a steam-electric generating unit, a Hybrid Resource, combined cycle unit, or a combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3(c) hereof), and where the real time LMP revenues at the unit's bus are lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit in an amount equal to {(AG ~~-~~ TRLD MWh~~LMPDMW~~) x (UB - URTLMP)}where:

AG equals the actual output of the unit;

TRLD MWh equals the Tracking Ramp Limited Desired MWh determined according to Operating Agreement, Schedule 1, section 3.2.3(e-1)~~LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the real time LMP at the unit's bus and adjusted for any Regulation or Synchronized Reserve assignments~~;

UB equals the unit offer for that unit for which output, or charging, is increased, determined according to the lesser of the Final Offer or Committed Offer;

URTLMP equals the real time LMP at the unit's bus; and

where UB - URTLMP shall not be negative, except where applicable for an Energy Storage Resource Model Participant or a Hybrid Resource when instructed to increase charging.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3(c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability or if an Energy Storage Resource Model Participant or a Hybrid Resource believes the above calculations in this section 3.2.3B do not accurately compensate the Market Participant for opportunity costs associated with following the Office of the Interconnection's dispatch instructions to modify a unit's charging or discharging for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate opportunity cost compensation, the Office of the Interconnection shall invoice the Market Participant accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in section 3.2.3A regarding provision of Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Synchronized Reserve Market Clearing Price for each Real-time Settlement Interval a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the product of the Condense Energy Use multiplied by the real time LMP at the generating unit's bus, (B) the generating unit's Condense Startup Cost, and (C) the unit-specific lost opportunity cost of the generating resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generating unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead

Market, but that is directed by the Office of the Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees in accordance with section 3.2.3(e-2). The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load ((a) net of operating Behind The Meter Generation; and (b) excluding Direct Charging Energy) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater

certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the applicable Synchronized Reserve Requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in section 3.2.3A regarding provision of Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Real-time Synchronized Reserve Market Clearing Price for each applicable interval a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the product of the Condense Energy Use multiplied by the real-time LMP at the generation bus of the generation resource, (B) the generation resource's Condense Startup Cost, and (C) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load ((a) net of operating Behind The Meter Generation; and (b) excluding Direct Charging Energy) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

Each Market Buyer shall be assessed Transmission Congestion Charges as specified in Operating Agreement, Schedule 1, section 5.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Operating Agreement, Schedule 1, section 5.

3.2.6 Emergency Energy.

(a) When the Office of the Interconnection has implemented Emergency procedures, resources offering Emergency energy are eligible to set real-time Locational Marginal Prices, capped at the energy offer cap plus the sum of the applicable Reserve Penalty Factors for the Synchronized Reserve Requirement and Primary Reserve Requirement, provided that the Emergency energy is needed to meet demand in the PJM Region.

(b) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each applicable interval of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(c) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each applicable interval of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(d) The net costs or net revenues associated with sales or purchases of energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each applicable interval of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Participant in accordance with the charges and credits specified in Operating Agreement, Schedule 1, sections 3.2.1 through 3.2.6, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the PJM

Manuals, to allow verification of the billing amounts and completion of the Market Participant's internal accounting.

(b) If deliveries to a Market Participant that has PJM Interchange meters in accordance with Operating Agreement, section 14 include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market Participant, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market Participant and the unmetered Market Participant specified by them to the Office of the Interconnection.

3.3A Economic Load Response Participants.

3.3A.1 Compensation.

Economic Load Response Participants shall be compensated pursuant to sections 3.3A.5 and/or 3.3A.6 of this Schedule, for demand reduction offers submitted in the Day-Ahead Energy Market or Real-time Energy Market that satisfy the Net Benefits Test of section 3.3A.4; that are scheduled by the Office of the Interconnection; and that follow the dispatch instructions of the Office of the Interconnection. Qualifying demand reductions shall be measured by: 1) comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of section 3.3A.2 or 3.3A.2.01, respectively; or 2) non-interval metered residential Direct Load Control customers, as metered on a current statistical sample of electric distribution company accounts, as described in the PJM Manuals or 3) by the MWs produced by on-Site Generators pursuant to the provisions of section 3.3A.2.02.

3.3A.2 Customer Baseline Load.

For Economic Load Response Participants that choose to measure demand reductions using an end-use customer's Customer Baseline Load ("CBL"), the CBL shall be determined using the following formula for such participant's Non-Variable Loads. Additionally, the following formula shall be used to determine a Peak Shaving Adjustment end-use customer's demand reductions when determining peak shaving performance rating as described in PJM Manual 19, unless an alternative CBL is approved pursuant to section 3.3A.2.01 of this schedule:

(a) The CBL for weekdays shall be the average of the highest 4 out of the 5 most recent load weekdays in the 45 calendar day period preceding the relevant load reduction event.

i. For the purposes of calculating the CBL for weekdays, weekdays shall not include:

1. NERC holidays;

2. Weekend days;

3. Event days. For the purposes of this section an event day shall be either:

(i) any weekday that an Economic Load Response Participant submits a settlement pursuant to section 3.3A.4 or 3.3A.5, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection; or

(ii) any weekday where the end-use customer location that is registered in the Economic Load Response program is also registered as a Demand Resource, and all end-use customer

locations on the relevant Economic Load Response registration have been dispatched by PJM during an emergency event.

4. Any weekday where the average daily event period usage is less than 25% of the average event period usage for the five days.

ii. If a 45-day period does not include 5 weekdays that meet the conditions in subsection (a)(i) of this section, provided there are 4 weekdays that meet the conditions in subsection (a)(i) of this section, the CBL shall be based on the average of those 4 weekdays. If there are not 4 eligible weekdays, the CBL shall be determined in accordance with subsection (iii) of this section.

iii. Section 3.3A.2(a)(i)(3) notwithstanding, if a 45-day period does not include 4 weekdays that meet the conditions in subsection (a)(i) of this section, event days will be used as necessary to meet the 4 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(b) The CBL for weekend days and NERC holidays shall be determined in accordance with the following provisions:

i. The CBL for Saturdays and Sundays/NERC holidays shall be the average of the highest 2 load days out of the 3 most recent Saturdays or Sundays/NERC holidays, respectively, in the 45 calendar day period preceding the relevant load reduction event, provided that the following days shall not be used to calculate a Saturday or Sunday/NERC holiday CBL:

1. Event days. For the purposes of this section an event day shall be either:

a. any Saturday and Sunday/NERC holiday that an Economic Load Response Participant submits a settlement pursuant to section 3.3A.5 or 3.3A.6, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection; or

b. any Saturday and Sunday/NERC holiday where the end-use customer that is registered in the Economic Load Response program is also registered as a Demand Resource, and all end-use customer locations on the relevant Economic Load Response registration have been dispatched by PJM during an emergency event.

2. Any Saturday or Sunday/NERC holiday where the average daily event period usage is less than 25% of the average event period usage level for the three days;

3. Any Saturday or Sunday/NERC holiday that corresponds to the beginning or end of daylight savings.

ii. If a 45-day period does not include 3 Saturdays or 3 Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, provided there are 2 Saturdays or Sundays/NERC holidays that meet the conditions in subsection (b)(i) of this section, the CBL will be based on the average of those 2 Saturdays or Sundays/NERC holidays. If there are not 2 eligible Saturdays or Sundays/NERC holidays, the CBL shall be determined in accordance with subsection (iii) of this section.

iii. Section 3.3A.2(b)(i)(1) notwithstanding, if a 45-day period does not include 2 Saturdays or Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, event days will be used as necessary to meet the 2 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(c) CBLs established pursuant to this section shall represent end-use customers' actual load patterns. If the Office of the Interconnection determines that a CBL or alternative CBL does not accurately represent a customer's actual load patterns, the CBL shall be revised accordingly pursuant to section 3.3A.2.01. Consistent with this requirement, if an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer upon whose behalf it is acting that would result in the adjustment of more than half the hours in the affected party's Customer Baseline Load by twenty percent or more for more than twenty days.

3.3A.2.01 Alternative Customer Baseline Methodologies.

(a) During the Economic Load Response Participant registration process pursuant to section 1.5A.3 of this Schedule, the relevant Economic Load Response Participant or the Office of the Interconnection ("Interested Parties") may, in the case of such participant's Non-Variable Load customers, and shall, in the case of its Variable Load customers, propose an alternative CBL calculation that more accurately reflects the relevant end-use customer's consumption pattern relative to the CBL determined pursuant to section 3.3A.2. During the Emergency and Pre-Emergency Load Response registration process pursuant to section 8.4 of this schedule, or as otherwise approved by the Office of the Interconnection, the relevant participant or the Office of the Interconnection may propose an alternative CBL calculation that more accurately reflects the relevant end-use customer's consumption pattern relative to the CBL determined pursuant to section 3.3A.2 of this schedule. In support of such proposal, the participant shall demonstrate that the alternative CBL method shall result in an hourly relative root mean square error of twenty percent or less compared to actual hourly values, as calculated in accordance with the technique specified in the PJM Manuals. Any proposal made pursuant to this section shall be provided to the other Interested Party.

(b) The Interested Parties shall have 30 days to agree on a proposal issued pursuant to subsection (a) of this section. The 30-day period shall start the day the proposal is provided to

the other Interested Party. If both Interested Parties agree on a proposal issued pursuant to this section, that alternative CBL calculation methodology shall be effective consistent with the date of the relevant Economic Load Response Participant registration.

(c) If agreement is not reached pursuant to subsection (b) of this section, the Office of the Interconnection shall determine a CBL methodology that shall result, as nearly as practicable, in an hourly relative root mean square error of twenty percent or less compared to actual hourly values within 20 days from the expiration of the 30-day period established by subsection (b). A CBL established by the Office of the Interconnection pursuant to this subsection (c) shall be binding upon both Interested Parties unless the Interested Parties reach agreement on an alternative CBL methodology prior to the expiration of the 20-day period established by this subsection (c).

(d) Operation of this section 3.3A.2.01 shall not delay Economic Load Response Participant registrations pursuant to Section 1.5A.3, provided that the alternative CBL established pursuant to this section shall be used for all related energy settlements made pursuant to sections 3.3A.5 and 3.3A.6.

(e) The Office of the Interconnection shall periodically publish alternative CBL methodologies established pursuant to this section in the PJM Manuals.

(f) Emergency and Pre-Emergency Load Response registrations will use the CBL defined on the associated economic registration for measuring demand reductions when determining the participant's compliance with its capacity obligations pursuant to Schedule 6 of the RAA, unless it is the maximum baseload CBL as defined in the PJM Manuals, in which case the participant will use the CBL set forth in the Emergency or Pre-Emergency Load Response registration.

3.3A.2.02 On-Site Generators.

On-Site Generators used as the basis for Economic Load Response Participant status pursuant to Tariff, Attachment K-Appendix, section 1.5A shall be subject to the following provisions:

i. The On-Site Generator shall be used solely to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market and shall not otherwise have been operating;

ii. If subsection (i) does not apply, the amount of energy from an On-Site Generator used to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market shall be capable of being quantified in a manner that is acceptable to the Office of the Interconnection.

3.3A.3 Symmetric Additive Adjustment.

(a) Customer Baseline Levels established pursuant to section 3.3A.2 shall be adjusted by the Symmetric Additive Adjustment. Unless an alternative formula is approved by the Office of the Interconnection, the Symmetric Additive Adjustment shall be calculated using the following formula:

Step 1: Calculate the average usage over the 3 hour period ending 1 hour prior to the start of event.

Step 2: Calculate the average usage over the 3 hour period in the CBL that corresponds to the 3 hour period described in Step 1.

Step 3: Subtract the results of Step 2 from the results of Step 1 to determine the symmetric additive adjustment (this may be positive or negative).

Step 4: Add the symmetric additive adjustment (i.e. the results of Step 3) to each hour in the CBL that corresponds to each event hour.

(b) Following a Load Reduction Event that is submitted to the Office of the Interconnection for compensation, the Office of the Interconnection shall provide the Notification window(s), if applicable, directly metered data and Customer Baseline Load and Symmetric Additive Adjustment calculation to the appropriate electric distribution company for optional review. The electric distribution company will have ten Business Days to provide the Office of the Interconnection with notification of any issues related to the metered data or calculations.

3.3A.4 Net Benefits Test.

The Office of the Interconnection shall identify each month the price on a supply curve, representative of conditions expected for that month, at which the benefit of load reductions provided by Economic Load Response Participants exceed the costs of those reductions to other loads. In formulaic terms, the net benefit is deemed to be realized at the price point on the supply curve where (Delta LMP x MWh consumed) > (LMP_{NEW} x DR), where LMP_{NEW} is the market clearing price after Economic Load Response is dispatched and Delta LMP is the price before Economic Load Response is dispatched minus the LMP_{NEW}).

The Office of the Interconnection shall update and post the Net Benefits Test results and analysis for a calendar month no later than the 15th day of the preceding calendar month. As more fully specified in the PJM Manuals, the Office of the Interconnection shall calculate the net benefit price level in accordance with the following steps:

Step 1. Retrieve generation offers from the same calendar month (of the prior calendar year) for which the calculation is being performed, employing market-based price offers to the extent available, and cost-based offers to the extent market-based price offers are not available. To the extent that generation offers are unavailable from historical data due to the addition of a Zone to the PJM Region the Office of the Interconnection shall use the most recent generation offers that

best correspond to the characteristics of the calendar month for which the calculation is being performed, provided that at least 30 days of such data is available. If less than 30 days of data is available for a resource or group of resources, such resource[s] shall not be considered in the Net Benefits Test calculation.

Step 2: Adjust a portion of each prior-year offer representing the typical share of fuel costs in energy offers in the PJM Region, as specified in the PJM Manuals, for changes in fuel prices based on the ratio of the reference month spot price to the study month forward price. For such purpose, natural gas shall be priced at the Henry Hub price, number 2 fuel oil shall be priced at the New York Harbor price, and coal shall be priced as a blend of coal prices representative of the types of coal typically utilized in the PJM Region.

Step 3. Combine the offers to create daily supply curves for each day in the period.

Step 4. Average the daily curves for each day in the month to form an average supply curve for the study month.

Step 5. Use a non-linear least squares estimation technique to determine an equation that reasonably approximates and smooths the average supply curve.

Step 6. Determine the net benefit level as the point at which the price elasticity of supply is equal to 1 for the estimated supply curve equation established in Step 5.

3.3A.5 Market Settlements in Real-time Energy Market.

(a) Economic Load Response Participants that submit offers for load reductions in the Day-ahead Energy Market by no later than 2:15 p.m. on the day prior to the Operating Day that cleared or that otherwise are dispatched by the Office of the Interconnection for the Operating Day shall be compensated for reducing demand based on the actual kWh relief provided in excess of committed day-ahead load reductions. The offer shall contain the Offer Data specified in Tariff, Attachment K-Appendix, section 1.10.1A(k) and shall not thereafter be subject to change; provided, however, the Economic Load Response Participant may update the previously specified minimum or maximum load reduction quantity and associated price by submitting a Real-time Offer for a clock hour by providing notice to the Office of the Interconnection in the form and manner specified in the PJM Manuals no later than 65 minutes prior to such clock hour. Economic Load Response Participants may also submit Real-time Offers for a clock hour for an Operating Day containing Offer Data specified in Tariff, Attachment K-Appendix, section 1.10.1A(k), and may update such offers up to 65 minutes prior to such clock hour. Economic Load Response Participants may, at their option, combine separately registered loads that have a common pricing point into a single portfolio for purposes of offering and dispatching their load reduction capability; provided however that any load reductions will continue to be measured and verified at the individual registration level prior to aggregation at the portfolio level for purposes of energy market and balancing ~~operating reserves~~energy uplift settlements. An Economic Load Response Participant that curtails or causes the curtailment of demand in real-time in response to PJM dispatch, and for which the

applicable real-time LMP is equal to or greater than the threshold price established under the Net Benefits Test, will be compensated by PJMSettlement at the real-time Locational Marginal Price.

(b) In cases where the demand reduction follows dispatch, as defined in Tariff, Attachment K-Appendix, section 3.2.3(o-1), as instructed by the Office of the Interconnection, and the demand reduction offer price is equal to or greater than the threshold price established under the Net Benefits Test, payment will not be less than the total value of the demand reduction bid. For the purposes of this subsection, the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing demand, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the demand reduction must be committed.

Any shortfall between the applicable Locational Marginal Price and the total value of the demand reduction bid will be made up through normal, ~~real-time operating reserves~~balancing Energy Make Whole credits. In all cases under this subsection, the applicable zonal or aggregate (including nodal) Locational Marginal Price shall be used as appropriate for the individual end-use customer. The foregoing notwithstanding, when calculating balancing Energy Make Whole credits for Economic Load Response Participants pursuant to Tariff, Attachment K-Appendix, section 3.2.3, the second Segment shall exclude shutdown costs.

(c) For purposes of load reductions qualifying for compensation hereunder, an Economic Load Response Participant shall accumulate credits for energy reductions in those hours when the energy delivered to the end-use customer is less than the end-use customer's Customer Baseline Load at the applicable Locational Marginal Price for the Real-time Settlement Interval. In the event that the end-use customer's hourly energy consumption is greater than the Customer Baseline Load, the Economic Load Response Participant will accumulate debits at the applicable Locational Marginal Price for the Real-time Settlement Interval for the amount the end-use customer's hourly energy consumption is greater than the Customer Baseline Load. If the actual load reduction, compared to the desired load reduction is outside the deviation levels specified in Tariff, Attachment K-Appendix, section 3.2.3(o-1), the Economic Load Response Participant shall be assessed balancing ~~operating reserve~~uplift charges equal to the Economic Load Response Participant's daily total of hourly deviations in each region times the regional adder rate for deviations in the relevant region plus the daily total of hourly deviations in the RTO region times the RTO region balancing uplift rate for deviations in accordance with Tariff, Attachment K-Appendix, section 3.2.3. The rates used for Economic Load Response Participant's balancing uplift charges are calculated in accordance with Tariff, Attachment K-Appendix, section 3.2.3(q-1), however the credits used in the calculation of the rates exclude balancing Energy Make Whole credits paid to Economic Load Response Participants. Market Participants with deviations in the RTO region, excluding Economic Load Response Participant deviations, shall be allocated any uplift credit associated with the collection of these charges.

(d) The cost of payments to Economic Load Response Participants under this section (excluding any portion of the payments recovered as ~~operating reserves~~balancing Energy Marke Whole credits pursuant to subsection (b) of this section) for load reductions that are compensated at the applicable full LMP, in any Zone for any hour, shall be recovered from Market

Participants on a ratio-share basis based on their real-time exports from the PJM Region and from Load Serving Entities on a ratio-share basis based on their real-time loads in each Zone for which the load-weighted average Locational Marginal Price for the hour during which such load reduction occurred is greater than or equal to the price determined under the Net Benefits Test for that month, with the ratio shares determined as follows:

The ratio share for LSE **i** in zone **z** shall be $\mathbf{RTL_{iz}/(RTL + X)}$
and the ratio share for party **j** shall be $\mathbf{X_j/(RTL + X)}$.

Where:

RTL is the total real time load in all zones where LMP ≥ Net Benefits Test price;
$\mathbf{RTL_{iz}}$ is the real-time load for LSE **i** in zone **z**;
X is the total export quantity from PJM in that hour; and
$\mathbf{X_j}$ is the export quantity by party **j** from PJM.

3.3A.6 Market Settlements in the Day-ahead Energy Market.

(a) Economic Load Response Participants dispatched as a result of a qualifying demand reduction offer in the Day-ahead Energy Market shall be compensated for reducing demand based on the reductions of kWh committed in the Day-ahead Energy Market. An Economic Load Response Participant that submits a demand reduction bid day ahead that is accepted by the Office of the Interconnection and for which the applicable day ahead LMP is greater than or equal to the Net Benefits Test shall be compensated by PJMSettlement at the day-ahead Locational Marginal Price.

Economic Load Response Participants may, at their option, combine separately registered loads that have a common pricing point into a single portfolio for purposes of offering and dispatching their load reduction capability; provided however that any load reductions will continue to be measured and verified at the individual registration level prior to aggregation at the portfolio level for purposes of energy market and balancing ~~operating reserves~~uplift settlements.

(b) Total payments to Economic Load Response Participants for accepted day-ahead demand reduction bids with an offer price equal to or greater than the threshold price established under the Net Benefits Test that follow the dispatch instructions of the Office of the Interconnection will not be less than the total value of the demand reduction bid. For the purposes of this subsection, the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing load, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the load reduction must be committed. Any shortfall between the applicable Locational Marginal Price and the total value of the demand reduction bid will be made up through normal, day-ahead ~~operating reserves~~Energy Make Whole credits. In all cases under this subsection, the applicable zonal or aggregate (including nodal) Locational Marginal Price shall be used as appropriate for the individual end-use customer.

(c) Economic Load Response Participants that have demand reductions committed in the Day-ahead Energy Market that deviate from the day-ahead schedule in real time shall be charged or credited for such variance at the real time LMP plus or minus an amount equal to the applicable balancing ~~operating reserve~~uplift charge in accordance with Tariff, Attachment K-Appendix, section 3.2.3. Load Serving Entities that otherwise would have load that was reduced shall receive any associated ~~operating reserve~~uplift credit.

(d) The cost of payments to Economic Load Response Participants for accepted day-ahead demand reduction bids that are compensated at the applicable full, day ahead LMP under this section (excluding any portion of the payments recovered as ~~operating reserves~~day-ahead Energy Make Whole credits pursuant to subsection (b) of this section) for load reductions in any Zone for any hour shall be recovered from Market Participants on a ratio-share basis based on their real-time exports from the PJM Region and from Load Serving Entities on a ratio-share basis based on their real-time loads in each Zone for which the load-weighted average real-time Locational Marginal Price for the hour during which such load reduction occurred is greater than or equal to the price determined under the Net Benefits Test for that month, in accordance with the formula prescribed in Tariff, Attachment K-Appendix, section 3.3A.5(d).

3.3A.7 Prohibited Economic Load Response Participant Market Settlements.

(a) Settlements pursuant to sections 3.3A.5 and 3.3A.6 shall be limited to demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market that satisfy the Net Benefits Test and are dispatched by the Office of the Interconnection.

(b) Demand reductions that do not meet the requirements of section 3.3A.7(a) shall not be eligible for settlement pursuant to sections 3.3A.5 and 3.3A.6. Examples of settlements prohibited pursuant to this section 3.3A.7(b) include, but are not limited to, the following:

i. Settlements based on variable demand where the timing of the demand reduction supporting the settlement did not change in direct response to Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market;

ii. Consecutive daily settlements that are the result of a change in normal demand patterns that are submitted to maintain a CBL that no longer reflects the relevant end-use customer's demand;

iii. Settlements based on on-site generation data if the On-Site Generator is not supporting demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market;

iv. Settlements based on demand reductions that are the result of operational changes between multiple end-use customer sites in the PJM footprint;

v. Settlements that do not include all hours that the Office of the Interconnection dispatched the load reduction, or for which the load reduction cleared in the Day-ahead Market.

(c) The Office of the Interconnection shall disallow settlements for demand reductions that do not meet the requirements of section 3.3A.7(a). If the Economic Load Response Participant continues to submit settlements for demand reductions that do not meet the requirements of section 3.3A.7(a), then the Office of the Interconnection shall suspend the Economic Load Response Participant's PJM Interchange Energy Market activity and refer the matter to the FERC Office of Enforcement.

3.3A.8 Economic Load Response Participant Review Process.

(a) The Office of the Interconnection shall review the participation of an Economic Load Response Participant in the PJM Interchange Energy Market under the following circumstances:

i. An Economic Load Response Participant's registrations submitted pursuant to Tariff, Attachment K-Appendix, section 1.5A.3 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).

ii. An Economic Load Response Participant's settlements pursuant to sections 3.3A.5 and 3.3A.6 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).

iii. An Economic Load Response Participant's settlements pursuant to sections 3.3A.5 and 3.3A.6 are denied by the Office of the Interconnection more than 10% of the time.

iv. An Economic Load Response Participant's registration will be reviewed when settlements are frequently submitted or if its actual loads frequently deviate from the previously scheduled quantities (as determined for purposes of assessing balancing ~~operating reserves~~uplift charges). PJM will notify the Participant when their registration is under review. While the Participant's registration is under review by PJM, the Participant may continue economic load reductions but all settlements will be denied by PJM until the registration review is resolved pursuant to subsection (i) or (ii) below. PJM will require the Participant to provide information within 30 days to support that the settlements were submitted for load reduction activity done in response to price and not submitted based on the end-use customer's normal operations.

i) If the Participant is unable to provide adequate supporting information to substantiate the load reductions submitted for settlement, PJM will terminate the registration and may refer the Participant to either the Market Monitoring Unit or the Federal Energy Regulatory Commission for further investigation.

ii) If the Participant does provide adequate supporting information, the settlements denied by PJM will be resubmitted by the Participant for review according to existing PJM market rules. Further, PJM may introduce an alternative Customer Baseline Load if the existing Customer Baseline Load does not adequately reflect what the customer load would have been absent a load reduction.

v. The electric distribution company may only deny settlements during the normal settlement review process for inaccurate data including, but not limited to: meter data, line loss factor, Customer Baseline Load calculation, interval meter owner and a known recurring end-use customer outage or holiday.

(b) The Office of the Interconnection shall have thirty days to conduct a review pursuant to this section 3.3A.8. The Office of the Interconnection may refer the matter to the PJM MMU and/or the FERC Office of Enforcement if the review indicates the relevant Economic Load Response Participant and/or relevant electric distribution company or LSE is engaging in activity that is inconsistent with the PJM Interchange Energy Market rules governing Economic Load Response Participants.

8.8 Market Settlements

Payment for reducing load is based on the actual kWh relief provided plus the adjustment for losses, subject to the Reporting and Compliance provisions below. The magnitude of capacity relief provided by Full Program Option participants shall be the amount determined in accordance with the Reporting and Compliance provisions below. The magnitude of relief provided by Energy Only Option participants, and the magnitude of energy relief provided by Full Program Option participants, may be less than, equal to, or greater than the kW amount declared on the Emergency or Pre-Emergency registration. Compensation will be provided for reductions in energy consumption during emergency events, tests and associated retest(s), where applicable by Full Program Option participants and Energy Only Option participants regardless of whether the participant's load during the event exceeds its peak load contribution for the applicable Delivery Year.

PJMSettlement pays the applicable LMP to the PJM Member that nominates the load. Payment will be equal to the measured energy load reduction adjusted for losses times the applicable LMP. The measured energy load reduction for locations with approved Economic Load Response registrations prior to a Load Management Event that have an economic CBL different than the maximum base load as defined in the PJM Manuals will use the associated economic CBL to determine the energy load reduction unless the locations on the Emergency Load Response registration are not the same locations as those included on the Economic Load Response registration. If, at the time that a Load Management Event or emergency event is initiated by PJM, an end-use customer is already responding economically (i.e., pursuant to the Economic Load Response rules) and economic CBL is based on Symmetric Additive Adjustment, then the CBL calculated based on the Symmetric Additive Adjustment period prior to the economic event will be used. Locations that do not have an approved Economic Load Response registration prior to a Load Management Event will use the Customer Baseline Load as defined in section 3.3A.2 and associated Symmetric Additive Adjustment as defined in section 3.3A.2.01 of this schedule unless an alternative CBL is approved pursuant to section 3.3A.2.01 of this schedule as the CBL to determine the energy load reduction.

If, however, the sum of the hourly energy payments to a Curtailment Service Provider with a Demand Resource Registration dispatched by PJM for actual, achieved reductions for an emergency event is not greater than or equal to the offer value (i.e. Minimum Dispatch Price and shut down costs) then the Curtailment Service Provider will be made whole up to the offer value for its actual, achieved reductions for the Demand Resource Registration.

Locations on Economic Load Response registrations dispatched in the Real-time Energy Market or cleared in the Day-ahead Energy Market that are also included on an Emergency Load Response and Pre-Emergency Load Response registration as Full Program Option, and that have also been dispatched as part of an emergency event for the same hour (i.e., have an "overlapping dispatch hour") will be compensated for energy based on emergency energy settlement and cost allocation rules as set forth in this section and in the PJM Manuals. Overlapping dispatch hours will use shutdown costs based on what was considered for the economic event, and no balancing ~~Operating Reserve~~uplift charges will be assessed for deviations from real-time dispatch amounts or from cleared day-ahead commitments. To avoid duplicative energy payments, overlapping

dispatch hours for an aggregate registration (i.e., multiple locations on the same registration) or dispatch groups where locations on the Emergency Load Response and Pre-Emergency Load Response registration are not the same locations as those on the Economic Load Response registration will have hourly economic energy load reduction and/or hourly emergency energy load reduction prorated based on load reduction capability provided by the Curtailment Service Provider for the locations.

The Curtailment Service Provider will only submit energy settlements for Load Management Events that occur outside of the specific availability period defined in the Reliability Assurance Agreement for each Demand Resource type if the Curtailment Service Provider has confirmed that the customers on the registration did take action to reduce load or the registration reflects the entire group of mass market customers for which an energy settlement will either be submitted for all or none of the mass market customers, as approved by PJM. The Curtailment Service Provider will only submit energy settlements for tests and for each registration for Load Management Events that occur during the product specific availability period as defined for each product in the Reliability Assurance Agreement if the Curtailment Service Provider also provides associated load data for each registration in order to calculate that registration's capacity compliance.

Full Program Option participants that fail to provide a load reduction (as measured as set forth in the Reporting and Compliance provisions below) when dispatched by PJM shall be assessed penalties and/or charges as specified in Tariff, Attachment DD and the Reliability Assurance Agreement, as applicable.

During emergency conditions, costs for emergency purchases in excess of LMP are allocated among PJM Market Buyers in proportion to their increase in net purchases minus real-time dispatch reduction megawatts from the PJM energy market during the hour in the Real-time Energy Market compared to the Day-ahead Energy Market. Consistent with this pricing methodology, all charges under the Emergency Load Response and Pre-Emergency Load Response Program are allocated to purchasers of energy, in proportion to their increase in net purchases minus real-time dispatch reduction megawatts from the PJM energy market during the hour from day-ahead to real-time.

The cost of payments for Emergency Load Response and Pre-Emergency Load Response energy settlements for tests, shall be recovered from Market Participants on a ratio-share basis based on their real-time exports from the PJM Region and from Load Serving Entities on ratio-share basis based on their real-time loads in each Zone for that month where the tests were conducted, with the ratio shares determined as follows:

The ratio share for LSE i in zone z shall be RTLiz/(RTL + X)
and the ratio share for party j shall be Xj/(RTL + X).
Where:

RTL is the total real time load in all zones where Load Management was tested;
RTLiz is the real-time load for LSE i in zone z;
X is the total export quantity from PJM in that hour; and

Xj is the export quantity by party j from PJM.

Emergency Load Response and Pre-Emergency Load Response Program charges and credits will appear on the PJM Members monthly bill, as described in the ***PJM Manual for Operating Agreement Accounting*** and the ***PJM Manual for Billing***.

Revisions to the
PJM Operating Agreement

(Clean Format)

Definitions A - B

30-minute Reserve:

"30-minute Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within 30 minutes of a request from the Office of the Interconnection dispatcher, and is comprised of Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve.

30-minute Reserve Requirement:

"30-minute Reserve Requirement" shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone, as Secondary Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The 30-minute Reserve Requirement is calculated in accordance with the PJM Manuals. The requirement can be satisfied by any combination of Synchronized Reserve, Non Synchronized Reserve or Secondary Reserve resources.

Acceleration Request:

"Acceleration Request" shall mean a request pursuant to Operating Agreement, Schedule 1, section 1.9.4A and the parallel provisions of Tariff, Attachment K-Appendix, to accelerate or reschedule a transmission outage scheduled pursuant to Operating Agreement, Schedule 1, section 1.9.2 or Operating Agreement, Schedule 1, section 1.9.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 1.9.2 and Tariff, Attachment K-Appendix, section 1.9.4.

Act:

"Act" shall mean the Delaware Limited Liability Company Act, Title 6, §§ 18-101 to 18-1109 of the Delaware Code.

Active and Significant Business Interest:

"Active and Significant Business Interest" is a term that shall be used to assess the scope of a Member's PJM membership and shall be based on a Member's activity in the PJM RTO and/or Interchange Energy Markets. A Member's Active and Significant Business Interest shall: 1) be determined relative to the scope of the Member's PJM membership and activity in the PJM RTO and/or Interchange Energy Markets considering, among other things, the Member's public statements and/or regulatory filings regarding its PJM activities; and 2) reflect a substantial contributor to the Member's recent market activity, revenues, costs, investment, and/or earnings when considering the Member and its corporate affiliates' interests within the PJM footprint.

Actual MWh

"Actual MWh" is equal to the real-time output of a resource as defined by the Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Tariff,

Attachment K-Appendix, section 3.1A and parallel provisions in Operating Agreement, Schedule 1, section 3.1A.

Affected Member:

"Affected Member" shall mean a Member of PJM which as a result of its participation in PJM's markets or its membership in PJM provided confidential information to PJM, which confidential information is requested by, or is disclosed to an Authorized Person under a Non-Disclosure Agreement.

Affiliate:

"Affiliate" shall mean any two or more entities, one of which Controls the other or that are under common Control. "Control," as that term is used in this definition, shall mean the possession, directly or indirectly, of the power to direct the management or policies of an entity. Ownership of publicly-traded equity securities of another entity shall not result in Control or affiliation for purposes of the Tariff or Operating Agreement if the securities are held as an investment, the holder owns (in its name or via intermediaries) less than 10 percent (10%) of the outstanding securities of the entity, the holder does not have representation on the entity's board of directors (or equivalent managing entity) or vice versa, and the holder does not in fact exercise influence over day-to-day management decisions. Unless the contrary is demonstrated to the satisfaction of the Members Committee, Control shall be presumed to arise from the ownership of or the power to vote, directly or indirectly, ten percent or more of the voting securities of such entity.

Agreement, Operating Agreement of the PJM Interconnection, L.L.C., Operating Agreement or PJM Operating Agreement:

"Agreement," "Operating Agreement of the PJM Interconnection, L.L.C.," "Operating Agreement" or "PJM Operating Agreement" shall mean this Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. dated as of April 1, 1997 and as amended and restated as of June 2, 1997, including all Schedules, Exhibits, Appendices, addenda or supplements thereto, as amended from time to time thereafter, among the Members of PJM Interconnection L.L.C., on file with the Commission.

Annual Meeting of the Members:

"Annual Meeting of the Members" shall mean the meeting specified in Operating Agreement, section 8.3.1.

Applicable Regional Entity:

"Applicable Regional Entity" shall mean the Regional Entity for the region in which a Network Customer, Transmission Customer, New Service Customer, or Transmission Owner operates.

Applicable Standards:

"Applicable Standards" shall mean the requirements and guidelines of NERC, the Applicable Regional Entity, and the Control Area in which the Customer Facility is electrically located; the PJM Manuals; and Applicable Technical Requirements and Standards.

Associate Member:

"Associate Member" shall mean an entity that satifies the requirements of Operating Agreement, section 11.7.

Auction Revenue Rights:

"Auction Revenue Rights" or "ARRs" shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Operating Agreement, Schedule 1, section 7.4 and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.

Auction Revenue Rights Credits:

"Auction Revenue Rights Credits" shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Authorized Commission:

"Authorized Commission" shall mean (i) a State public utility commission that regulates the distribution or supply of electricity to retail customers and is legally charged with monitoring the operation of wholesale or retail markets serving retail suppliers or customers within its State or (ii) an association or organization comprised exclusively of State public utility commissions described in the immediately preceding clause (i).

Authorized Person:

"Authorized Person" shall have the meaning set forth in Operating Agreement, section 18.17.4.

Balancing Congestion Charges:

"Balancing Congestion Charges" shall be equal to the sum of congestion charges collected from Market Participants that are purchasing energy in the Real-time Energy Market minus [the sum of congestion charges paid to Market Participants that are selling energy in the Real-time Energy Market plus any congestion charges calculated pursuant to the Joint Operating Agreement between the Midcontinent Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38), plus any congestion charges calculated pursuant to the Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 45), plus any congestion charges calculated pursuant to agreements between the Office of the Interconnection and other entities, plus any charges or credits calculated pursuant to

Operating Agreement, Schedule 1, section 3.8, and the parallel provisions of Tariff, Attachment K-Appendix, section 3.8, as applicable)].

Batch Load Economic Load Response Participant Resource:

"Batch Load Economic Load Response Participant Resource" shall mean an Economic Load Response Participant Resource that has a cyclical production process such that at most times during the process it is consuming energy, but at consistent regular intervals, ordinarily for periods of less than ten minutes, it reduces its consumption of energy for its production processes to minimal or zero megawatts.

Behind The Meter Generation:

"Behind The Meter Generation" shall refer to a generating unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of the Interconnection); provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit's capacity that is designated as a Generation Capacity Resource, or (ii) in any hour, any portion of the output of such generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.

Board Member:

"Board Member" shall mean a member of the PJM Board.

Definitions E - F

Economic-based Enhancement or Expansion:

"Economic-based Enhancement or Expansion" shall mean an enhancement or expansion described in Operating Agreement, Schedule 6, section 1.5.7(b) (i) – (iii) that is designed to relieve transmission constraints that have an economic impact.

Economic Load Response Participant:

"Economic Load Response Participant" shall mean a Member or Special Member that qualifies under Operating Agreement, Schedule 1, section 1.5A, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A to participate in the PJM Interchange Energy Market and/or Ancillary Services markets through reductions in demand.

Economic Maximum:

"Economic Maximum" shall mean the highest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Economic Minimum:

"Economic Minimum" shall mean the lowest incremental MW output level, submitted to PJM market systems by a Market Participant, that a unit can achieve while following economic dispatch.

Effective Date:

"Effective Date" shall mean August 1, 1997, or such later date that FERC permits the Operating Agreement to go into effect.

Effective FTR Holder:

"Effective FTR Holder" shall mean:

(i) For an FTR Holder that is either a (a) privately held company, or (b) a municipality or electric cooperative, as defined in the Federal Power Act, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other entity that is under common ownership, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or

(ii) For an FTR Holder that is a publicly traded company including a wholly owned subsidiary of a publicly traded company, such FTR Holder, together with any Affiliate, subsidiary or parent of the FTR Holder, any other PJM Member has over 10% common

ownership with the FTR Holder, wholly or partly, directly or indirectly, or has the ability to influence, directly or indirectly, the management or policies of the FTR Holder; or

(iii) an FTR Holder together with any other PJM Member, including also any Affiliate, subsidiary or parent of such other PJM Member, with which it shares common ownership, wholly or partly, directly or indirectly, in any third entity which is a PJM Member (e.g., a joint venture).

EIDSN, Inc.:

"EIDSN, Inc." shall mean the nonstock, nonprofit corporation, formerly known as Eastern Interconnection Data Sharing Network, Inc., or any successor thereto, that is operated primarily for the purpose of developing operating tools and the facilitation of the secure, consistent, effective, and efficient sharing of important electric transmission and operational data among Reliability Coordinators and other relevant parties to help improve electric industry operations and promote the reliable and efficient operation of the bulk electric system in the Eastern Interconnection.

Electric Distributor:

"Electric Distributor" shall mean a Member that: 1) owns or leases with rights equivalent to ownership electric distribution facilities that are used to provide electric distribution service to electric load within the PJM Region; or 2) is a generation and transmission cooperative or a joint municipal agency that has a member that owns electric distribution facilities used to provide electric distribution service to electric load within the PJM Region.

Eligible Fast-Start Resource:

"Eligible Fast-Start Resource" shall mean a Fast-Start Resource that is eligible for the application of Integer Relaxation during the calculation of Locational Marginal Prices as set forth in Tariff, Attachment K-Appendix, section 2.2.

Emergency:

"Emergency" shall mean: (i) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of emergency procedures as defined in the PJM Manuals.

Emergency Load Response Program:

"Emergency Load Response Program" shall mean the program by which Curtailment Service Providers may be compensated by PJM for Demand Resources that will reduce load when dispatched by PJM during emergency conditions, and is described in Operating Agreement, Schedule 1, section 8 and the parallel provisions of Tariff, Attachment K-Appendix, section 8.

End-Use Customer:

"End-Use Customer" shall mean a Member that is a retail end-user of electricity within the PJM Region. For purposes of Member Committee classification, a Member that is a retail end-user that owns generation may qualify as an End-Use Customer if: (1) the average physical unforced capacity owned by the Member and its affiliates in the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the average PJM capacity obligation for the Member and its affiliates over the same time period; or (2) the average energy produced by the Member and its affiliates within the PJM region over the five Planning Periods immediately preceding the relevant Planning Period does not exceed the average energy consumed by that Member and its affiliates within the PJM region over the same time period. The foregoing notwithstanding, taking retail service may not be sufficient to qualify a Member as an End-Use Customer.

Energy Make Whole

"Energy Make Whole" shall refer to energy uplift provided to make a resource whole for costs incurred as specified in Tariff, Attachment K-Appendix, section 3.2.3 and parallel provisions in Operating Agreement, Schedule 1, section 3.2.3.

Energy Market Opportunity Cost:

"Energy Market Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of available run hours due to limitations imposed on the unit by Applicable Laws and Regulations and (b) the forecasted future Locational Marginal Price at which the generating unit could run while not violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Operating Agreement, Schedule 2.

Energy Storage Resource:

"Energy Storage Resource" shall mean a resource capable of receiving electric energy from the grid and storing it for later injection to the grid that participates in the PJM Energy, Capacity and/or Ancillary Services markets as a Market Participant. Open-Loop Hybrid Resources are not Energy Storage Resources.

Energy Storage Resource Model Participant:

"Energy Storage Resource Model Participant" shall mean an Energy Storage Resource utilizing the Energy Storage Resource Participation Model.

Energy Storage Resource Participation Model:

"Energy Storage Resource Participation Model" shall mean the participation model accepted by the Commission in Docket No. ER19-469-000.

Equivalent Load:

"Equivalent Load" shall mean the sum of a Market Participant's net system requirements to serve its customer load in the PJM Region, if any, plus its net bilateral transactions.

Extended Primary Reserve Requirement:

"Extended Primary Reserve Requirement" shall equal the Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Primary Reserve Requirement is calculated in accordance with the PJM Manuals.

Extended Synchronized Reserve Requirement:

"Extended Synchronized Reserve Requirement" shall equal the Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals.

Extended 30-minute Reserve Requirement:

"Extended 30-minute Reserve Requirement" shall equal the 30-minute Reserve Requirement in a Reserve Zone or Reserve Sub-zone, plus 190 MW, plus any additional reserves scheduled under emergency conditions necessary to address operational uncertainty. The Extended 30-minute Reserve Requirement is calculated in accordance with the PJM Manuals.

External Market Buyer:

"External Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for consumption by end-users outside the PJM Region, or for load in the PJM Region that is not served by Network Transmission Service.

External Resource:

"External Resource" shall mean a generation resource located outside the metered boundaries of the PJM Region.

Fast-Start Resource:

"Fast-Start Resource" shall have the meaning set forth in Tariff, Attachment K-Appendix, section 2.2A

FERC or Commission:

"FERC" or "Commission" shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department exercising jurisdiction over the Tariff, Operating Agreement and Reliability Assurance Agreement.

Final Offer:

"Final Offer" shall mean the offer on which a resource was dispatched by the Office of the Interconnection for a particular clock hour for an Operating Day.

Finance Committee:

"Finance Committee" shall mean the body formed pursuant to Operating Agreement, section 7.5.1.

Financial Transmission Right:

"Financial Transmission Right" or "FTR" shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2.

Financial Transmission Right Obligation:

"Financial Transmission Right Obligation" shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(b), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(c).

Financial Transmission Right Option:

"Financial Transmission Right Option" shall mean a right to receive Transmission Congestion Credits as specified in Operating Agreement, Schedule 1, section 5.2.2(c), and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.2(c).

Flexible Resource:

"Flexible Resource" shall mean a generating resource that must have a combined Start-up Time and Notification Time of less than or equal to two hours; and a Minimum Run Time of less than or equal to two hours.

Form 715 Planning Criteria:

"Form 715 Planning Criteria" shall mean individual Transmission Owner FERC-filed planning criteria as described in Operating Agreement, Schedule 6, section 1.2(e) and filed with FERC Form No. 715 and posted on the PJM website.

FTR Holder:

"FTR Holder" shall mean the PJM Member that has acquired and possesses an FTR.

Fuel Cost Policy:

"Fuel Cost Policy" shall mean the document provided by a Market Seller to PJM and the Market Monitoring Unit in accordance with PJM Manual 15 and Operating Agreement, Schedule 2, which documents the Market Seller's method used to price fuel for calculation of the Market Seller's cost-based offer(s)for a generation resource.

Definitions S – T

Sector Votes:

"Sector Votes" shall mean the affirmative and negative votes of each sector of a Senior Standing Committee, as specified in Operating Agreement, section 8.4.

Securities:

"Securities" shall mean negotiable or non-negotiable investment or financing instruments that can be sold and bought. Securities include bonds, stocks, debentures, notes and options.

Segment:
"Segment" shall have the same meaning as described in Operating Agreement, Schedule 1, section 3.2.3(e)and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(e).

Senior Standing Committees:

"Senior Standing Committees" shall mean the Members Committee, and the Markets and Reliability Committee, as established in Operating Agreement, section 8.1 and Operating Agreement, section 8.6.

SERC:

"SERC" or "Southeastern Electric Reliability Council" shall mean the reliability council under section 202 of the Federal Power Act established pursuant to the SERC Agreement dated January 14, 1970, or any successor thereto.

Short-term Project:

"Short-term Project" shall mean a transmission enhancement or expansion with an in-service date of more than three years but no more than five years from the year in which, pursuant to Operating Agreement, Schedule 6, section 1.5.8(c), the Office of the Interconnection posts the violations, system conditions, or Public Policy Requirements to be addressed by the enhancement or expansion.

Special Member:

"Special Member" shall mean an entity that satisfies the requirements of Operating Agreement, Schedule 1, section 1.5A.02, and the parallel provisions of Tariff, Attachment K-Appendix, section 1.5A.02, or the special membership provisions established under the Emergency Load Response and Pre-Emergency Load Response Programs.

Spot Market Backup:

"Spot Market Backup" shall mean the purchase of energy from, or the delivery of energy to, the PJM Interchange Energy Market in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason.

Spot Market Energy:

"Spot Market Energy" shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at System Energy Prices determined as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Standing Committees:

"Standing Committees" shall mean the Members Committee, the committees established and maintained under Operating Agreement, section 8.6, and such other committees as the Members Committee may establish and maintain from time to time.

Start Fuel:

For units without a soak process, "Start Fuel" shall consist of fuel consumed from first fire of the start process to first breaker closing, plus any fuel expended from last breaker opening to shutdown.

For units with a soak process, "Start Fuel" is fuel consumed from first fire of the start process (initial reactor criticality for nuclear units) to dispatchable output (including auxiliary boiler fuel), plus any fuel expended from last breaker opening to shutdown, excluding normal plant heating/auxiliary equipment fuel requirements. Start Fuel included for each temperature state from breaker closure to dispatchable output shall not exceed the unit specific soak time period reviewed and approved as part of the unit-specific parameter process detailed in Tariff, Attachment K-Appendix, section 6.6(c) or the defaults below:

- Cold Soak Time = 0.73 * unit specific Minimum Run Time (in hours)
- Intermediate Soak Time = 0.61 * unit specific Minimum Run Time (in hours)
- Hot Soak Time = 0.43 * unit specific Minimum Run Time (in hours)

Start-Up Costs:

"Start-Up Costs" shall consist primarily of the cost of fuel, as determined by the unit's start heat input (adjusted by the performance factor) times the fuel cost. It also includes operating costs, Maintenance Adders, emissions allowances/adders, and station service cost. Start-Up Costs can vary with the unit offline time being categorized in three unit temperature conditions: hot, intermediate and cold.

For units with a steam turbine and a soak process (nuclear, steam, and combined cycle), "Start Fuel" is fuel consumed from first fire of start process (initial reactor criticality for nuclear units):

Start-Up Costs shall mean the net unit costs from PJM's notification to the level at which the unit can follow PJM's dispatch, and from last breaker open to shutdown.

For units without a steam turbine and no soak process (engines, combustion turbines, Intermittent Resources, and Energy Storage Resources): Start-Up Costs shall mean the unit costs from PJM's notification to first breaker close and from last breaker open to shutdown.

State:

"State" shall mean the District of Columbia and any State or Commonwealth of the United States.

State Certification:

"State Certification" shall mean the Certification of an Authorized Commission, pursuant to Operating Agreement, section 18, the form of which is appended to the Operating Agreement as Operating Agreement, Schedule 10A, wherein the Authorized Commission identifies all Authorized Persons employed or retained by such Authorized Commission, a copy of which shall be filed with FERC.

State Consumer Advocate:

"State Consumer Advocate" shall mean a legislatively created office from any State, all or any part of the territory of which is within the PJM Region, and the District of Columbia established, inter alia, for the purpose of representing the interests of energy consumers before the utility regulatory commissions of such states and the District of Columbia and the FERC.

State Estimator:

"State Estimator" shall mean the computer model of power flows specified in Operating Agreement, Schedule 1, section 2.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.3.

State of Charge:

"State of Charge" shall mean the quantity of physical energy stored in an Energy Storage Resource Model Participant or in a storage component of a Hybrid Resource in proportion to its maximum State of Charge capability. State of Charge is quantified as defined in the PJM Manuals.

State of Charge Management:

"State of Charge Management" shall mean the control of State of Charge of an Energy Storage Resource Market Participant or a storage component of a Hybrid Resource using minimum and maximum discharge (and, as applicable, charge) limits, changes in operating mode (as

applicable), discharging (and, as applicable, charging) offer curves, and self-scheduling of non-dispatchable sales (and, as applicable, purchases) of energy in the PJM markets. State of Charge Management shall not interfere with the obligation of a Market Seller of an Energy Storage Resource Model Participant or of a Hybrid Resource to follow PJM dispatch, consistent with all other resources.

Station Power:

"Station Power" shall mean energy used for operating the electric equipment on the site of a generation facility located in the PJM Region or for the heating, lighting, air-conditioning and office equipment needs of buildings on the site of such a generation facility that are used in the operation, maintenance, or repair of the facility. Station Power does not include any energy (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility; (iii) used in association with restoration or black start service; or (iv) that is Direct Charging Energy.

Sub-meter:

"Sub-meter" shall mean a metering point for electricity consumption that does not include all electricity consumption for the end-use customer as defined by the electric distribution company account number. PJM shall only accept sub-meter load data from end-use customers for measurement and verification of Regulation service as set forth in the Economic Load Response rules and PJM Manuals.

Subregional RTEP Project:

"Subregional RTEP Project" shall mean a transmission expansion or enhancement rated below 230 kV which is required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.

Supplemental Project:

"Supplemental Project" shall mean a transmission expansion or enhancement that is not required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection and is not a state public policy project pursuant to Operating Agreement, Schedule 6, section 1.5.9(a)(ii). Any system upgrades required to maintain the reliability of the system that are driven by a Supplemental Project are considered part of that Supplemental Project and are the responsibility of the entity sponsoring that Supplemental Project.

Synchronized Reserve:

"Synchronized Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Economic Load Response Participant resources whose demand can be reduced within ten minutes from the request of the Office of the Interconnection

dispatcher, and is provided by equipment that is electrically synchronized to the Transmission System.

Synchronized Reserve Event:

"Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources and/or Economic Load Response Participant resources able, assigned or self-scheduled to provide Synchronized Reserve in one or more specified Reserve Zones or Reserve Sub-zones, within ten minutes, to increase the energy output or reduce load by a directed amount of the assigned or self-scheduled Synchronized Reserve.

Synchronized Reserve Requirement:

"Synchronized Reserve Requirement" shall mean the megawatts required to be maintained in a Reserve Zone or Reserve Sub-zone as Synchronized Reserve, absent any increase to account for additional reserves scheduled to address operational uncertainty. The Synchronized Reserve Requirement is calculated in accordance with the PJM Manuals. This requirement can only be satisfied by Synchronized Reserve resources.

System:

"System" shall mean the interconnected electric supply system of a Member and its interconnected subsidiaries exclusive of facilities which it may own or control outside of the PJM Region. Each Member may include in its system the electric supply systems of any party or parties other than Members which are within the PJM Region, provided its interconnection agreements with such other party or parties do not conflict with such inclusion.

System Energy Price:

"System Energy Price" shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, calculated as specified in Operating Agreement, Schedule 1, section 2, and the parallel provisions of Tariff, Attachment K-Appendix, section 2.

Target Allocation:

"Target Allocation" shall mean the allocation of Transmission Congestion Credits as set forth in Operating Agreement, Schedule 1, section 5.2.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.3 or the allocation of Auction Revenue Rights Credits as set forth in Operating Agreement, Schedule 1, section 7.4.3, and the parallel provisions of Tariff, Attachment K-Appendix, section 7.4.3.

Third Party Request:

"Third Party Request" shall mean any request or demand by any entity upon an Authorized Person or an Authorized Commission for release or disclosure of confidential information

provided to the Authorized Person or Authorized Commission by the Office of the Interconnection or the Market Monitoring Unit. A Third Party Request shall include, but shall not be limited to, any subpoena, discovery request, or other request for confidential information made by any: (i) federal, state, or local governmental subdivision, department, official, agency or court, or (ii) arbitration panel, business, company, entity or individual.

Tie Line:

"Tie Line" shall have the same meaning provided in the Open Access Transmission Tariff.

Total Lost Opportunity Cost Offer:

"Total Lost Opportunity Cost Offer" shall mean the applicable offer used to calculate lost opportunity cost credits. For pool-scheduled resources specified in PJM Operating Agreement, Schedule 1, section 3.2.3(f-1) and the parallel provisions of Tariff, Attachment K-Appendix, section 3.2.3(f-1), the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the greater of the Committed Offer or last Real-Time Offer submitted for the offer on which the resource was committed in the Day-ahead Energy Market for each hour in an Operating Day. For all other pool-scheduled resources, the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, as determined by the offer curve associated with the greater of the Committed Offer or Final Offer for each hour in an Operating Day. For self-scheduled generation resources, the Total Lost Opportunity Cost Offer shall equal the Real-time Settlement Interval offer integrated under the applicable offer curve for the LOC Deviation, where for self-scheduled generation resources (a) operating pursuant to a cost-based offer, the applicable offer curve shall be the greater of the originally submitted cost-based offer or the cost-based offer that the resource was dispatched on in real-time; or (b) operating pursuant to a market-based offer, the applicable offer curve shall be determined in accordance with the following process: (1) select the greater of the cost-based day-ahead offer and updated costbased Real-time Offer; (2) for resources with multiple cost-based offers, first, for each cost-based offer select the greater of the day-ahead offer and updated Real-time Offer, and then select the lesser of the resulting cost-based offers; and (3) compare the offer selected in (1), or for resources with multiple cost-based offers the offer selected in (2), with the market-based day-ahead offer and the market-based Real-time Offer and select the highest offer.

Tracking Ramp Limited Desired

"Tracking Ramp Limited Desired" shall mean the desired MW or MWh calculated pursuant to Tariff, Attachment K-Appendix, section 3.2.3(e-1) and parallel provisions in Operating Agreement, Schedule 1, section 3.2.3(e-1).

Transmission Congestion Charge:

"Transmission Congestion Charge" shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is

operating under constrained conditions, or as necessary to provide energy for third-party transmission losses, which shall be calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.1, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.1.

Transmission Congestion Credit:

"Transmission Congestion Credit" shall mean the allocated share of total Transmission Congestion Charges credited to each FTR Holder, calculated and allocated as specified in Operating Agreement, Schedule 1, section 5.2 and the parallel provisions of Tariff, Attachment K-Appendix, section 5.2.

Transmission Customer:

"Transmission Customer" shall have the meaning set forth in the PJM Tariff.

Transmission Facilities:

"Transmission Facilities" shall mean facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERC's Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the PJM Region transmission system and integrated into the planning and operation of the PJM Region to serve all of the power and transmission customers within the PJM Region.

Transmission Forced Outage:

"Transmission Forced Outage" shall mean an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the PJM Manuals. A removal from service of a transmission facility at the request of the Office of the Interconnection to improve transmission capability shall not constitute a Forced Transmission Outage.

Transmission Loading Relief:

"Transmission Loading Relief" shall mean NERC's procedures for preventing operating security limit violations, as implemented by PJM as the security coordinator responsible for maintaining transmission security for the PJM Region.

Transmission Loss Charge:

"Transmission Loss Charge" shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Operating Agreement, Schedule 1, section 5, and the parallel provisions of Tariff, Attachment K-Appendix, section 5.

Transmission Operator:

"Transmission Operator" shall have the same meaning set forth in the NERC Glossary of Terms used in NERC Reliability Standards.

Transmission Owner:

"Transmission Owner" shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

Transmission Owner Upgrade:

"Transmission Owner Upgrade" shall mean an upgrade to a Transmission Owner's own transmission facilities, which is an improvement to, addition to, or replacement of a part of, an existing facility and is not an entirely new transmission facility.

Transmission Planned Outage:

"Transmission Planned Outage" shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in Operating Agreement, Schedule 1, and the parallel provisions of Tariff, Attachment K-Appendix, or the PJM Manuals.

Turn Down Ratio:

"Turn Down Ratio" shall mean the ratio of a generating unit's economic maximum megawatts to its economic minimum megawatts.

18.17 Confidentiality.

18.17.1 Party Access.

(a) No Member shall have a right hereunder to receive or review any documents, data or other information of another Member, including documents, data or other information provided to the Office of the Interconnection, to the extent such documents, data or information have been designated as confidential pursuant to the procedures adopted by the Office of the Interconnection and/or the Market Monitoring Unit or to the extent that they have been designated as confidential by such other Member; provided, however, a Member may receive and review any composite documents, data and other information that may be developed based on such confidential documents, data or information if the composite does not disclose any individual Member's confidential data or information.

(b) Except as may be provided in this Agreement or in the PJM Open Access Transmission Tariff, the Office of the Interconnection shall not disclose to its Members or to third parties, any documents, data, or other information of a Member or entity applying for Membership, to the extent such documents, data, or other information has been designated confidential pursuant to the procedures adopted by the Office of the Interconnection or by such Member or entity applying for membership; provided that nothing contained herein shall prohibit the Office of the Interconnection from providing any such confidential information to its agents, representatives, or contractors to the extent that such person or entity is bound by an obligation to maintain such confidentiality; provided further that nothing contained herein shall prohibit the Office of the Interconnection from providing Member confidential information to the NERC, EIDSN, Inc., any Applicable Regional Entity, any Reliability Coordinator, any Transmission Operator, and the agents, representatives, or contractors of such entity, to the extent that (i) the Office of the Interconnection determines in its reasonable discretion that the exchange of such information is required to enhance and/or maintain reliability within the Members' Applicable Regional Entities and their neighboring Regional Entities, or within the region of any Reliability Coordinator, (ii) such entity is bound by a written agreement to maintain such confidentiality, and (iii) the Office of the Interconnection has notified the affected party of its intention to release such information no less than five Business Days prior to the release. The Office of the Interconnection, its designated agents, representatives, and contractors shall maintain as confidential the electronic tag ("e-Tag") data of an e-Tag Author or Balancing Authority (defined as those terms are used in FERC Order No. 771) to the same extent as Member data under this section 18.17. Nothing contained herein shall prohibit the Office of the Interconnection or its designated agents, representatives, or contractors from providing to another Regional Transmission Organization ("RTO") or Independent System Operator ("ISO"), upon their request, the e-Tags of an e-Tag Author or Balancing Authority for intra-PJM Region transactions and interchange transactions scheduled to flow into, out of or through the PJM Region, to the extent such RTO or ISO has requested such information as part of its investigation of possible market violations or market design flaws, and to the extent that such RTO or ISO is bound by a tariff provision requiring that the e-Tag data be maintained as confidential or, in the absence of a tariff requirement governing confidentiality, a written agreement with the Office of the Interconnection consistent with FERC Order No. 771 and any clarifying orders and implementing regulations. The Office of the Interconnection shall collect and use confidential

information only in connection with its authority under this Agreement and the Open Access Transmission Tariff and the retention of such information shall be in accordance with the Office of the Interconnection's data retention policies.

(c) Nothing contained herein shall prevent the Office of the Interconnection from releasing a Member's confidential data or information to a third party provided that the Member has delivered to the Office of the Interconnection and/or the Market Monitoring Unit specific, written authorization for such release setting forth the data or information to be released, to whom such release is authorized, and the period of time for which such release shall be authorized. The Office of the Interconnection shall limit the release of a Member's confidential data or information to that specific authorization received from the Member. Nothing herein shall prohibit a Member from withdrawing such authorization upon written notice to the Office of the Interconnection, who shall cease such release as soon as practicable after receipt of such withdrawal notice.

(d) Reciprocal provisions to this section 18.17.1, Operating Agreement, section18.17.2, Operating Agreement, section 18.17.3, Operating Agreement, section18.17.4 and Operating Agreement, section 18.17.5 , delineating the confidentiality requirements of PJM's Market Monitoring Unit, are set forth in Tariff, Attachment M – Appendix, section I.

(e) Notwithstanding anything to the contrary in this Agreement or in the PJM Tariff, the Office of the Interconnection shall post the following on its website:

(i) the non-aggregated bid data and Offer Data submitted by Market Participants (for participation on the PJM Interchange Energy Market) approximately four months after the bid or offer was submitted to the Office of the Interconnection to allow the tracking of Market Participants' non-aggregated bids and offers over time as required by FERC Order No. 719. However, to protect the confidential, market sensitive and/or proprietary bidding strategies of Market Participants as well as the identity of Market Participants from being discernible from the published data, the posted information will not reveal the (a) name of the resource, (b) characteristics of a specific resource, (c) identity of the load, (d) name of the individual or entity submitting the data, (e) identity of the resource owner, or (f) location of the resource at a level lower than its Zone. The Office of the Interconnection also reserves the right to take any other precautionary measures that it deems appropriate to preserve the confidential, market sensitive and/or proprietary bidding strategies of Market Participants to the extent not specifically set forth herein.

(ii) Within 20 calendar days after the end of each month, (a) the total daily uplift credits by Zone as set forth in Tariff, Attachment J, and RAA, Schedule 15, and applicable uplift charge codes (including lost opportunity cost contained within energy uplift) and (b) the total daily uplift charges by applicable PJM Region or Zone, as set forth in Tariff, Attachment J and RAA, Schedule 15, and applicable uplift charge codes along with relevant subcategories by which they are allocated. The Office of the Interconnection shall incorporate the best available information at the time the posting is created.

(iii) Within 90 calendar days after the end of each month, the name of each generation resource unit and amount of uplift credit payments by applicable uplift charge codes (including lost opportunity cost contained within energy uplift, but excluding Black Start Service) for each resource unit that received uplift credits in that month. For Demand Resources or Economic Load Response Participants, the Office of Interconnection shall post, within 90 calendar days after the end of each month, the individual resource identification number associated with the Demand Resource or Economic Load Response Participant's relevant dispatch group or registration, the name of the associated Curtailment Service Provider, the Zone and energy pricing point used to settle the Demand Resource or Economic Load Response Participant's dispatch group or registration, and the corresponding amount of uplift credits by applicable uplift charge codes for the dispatch group or registration that received uplift credits in that month. The Office of Interconnection shall incorporate the best available information at the time the posting is created.

(iv) Within 30 calendar days after the end of each month, each Operator-initiated Commitment listing the size of the commitment in megawatts (where megawatts are equal to the economic maximum), Zone (as set forth in Tariff, Attachment J and RAA, Schedule 15), commitment reason, and commitment start time. Commitment reasons shall include, but are not limited to, system wide capacity, constraint management, and voltage support.

(f) To the extent permitted pursuant to 18 C.F.R. §38.2 (or successor provisions), nothing contained herein shall prohibit the Office of the Interconnection from sharing non-public, operational information with an interstate natural gas pipeline operator for the purpose of promoting reliable service or operational planning. Further, the Office of the Interconnection shall be permitted to share non-public, operational information with natural gas local distribution companies and/or intrastate natural gas pipeline operators, as appropriate, for the purpose of promoting reliable service or operational planning, provided that such party has acknowledged, in writing, that it shall not disclose, or use anyone as a conduit for disclosure of, non-public, operational information received from the Office of Interconnection to a third party or in an unduly discriminatory or preferential manner or to the detriment of any natural gas and/or electric market. Such non-public, operational information received from natural gas local distribution companies and/or intrastate natural gas pipeline operators pursuant to this section will be subject to the confidentiality provisions set forth in this section 18.17.

18.17.2 Required Disclosure.

(a) Notwithstanding anything in the foregoing section to the contrary, and subject to the provisions of section 18.17.3 below, if the Office of the Interconnection is required by applicable law, order, or in the course of administrative or judicial proceedings, to disclose to third parties, information that is otherwise required to be maintained in confidence pursuant to this Agreement, the Office of the Interconnection or its designated agents, representatives, or contractors may make disclosure of such information; provided, however, that as soon as the Office of the Interconnection learns of the disclosure requirement and prior to it or its designated agents, representatives, or contractors making disclosure, the Office of the Interconnection shall notify the affected Member or Members of the requirement and the terms thereof and the affected Member or Members may direct, at their sole discretion and cost, any challenge to or

defense against the disclosure requirement. The Office of the Interconnection shall cooperate with such affected Members to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. The Office of the Interconnection shall cooperate with the affected Members to obtain proprietary or confidential treatment of such information by the person to whom such information is disclosed prior to any such disclosure.

(b) Nothing in this section 18.17 shall prohibit or otherwise limit the Office of the Interconnection's use of information covered herein if such information was: (i) previously known to the Office of the Interconnection without an obligation of confidentiality; (ii) independently developed by or for the Office of the Interconnection using non-confidential information; (iii) acquired by the Office of the Interconnection from a third party which is not, to the Office of the Interconnection's knowledge, under an obligation of confidence with respect to such information; (iv) which is or becomes publicly available other than through a manner inconsistent with this section 18.17.

(c) The Office of the Interconnection shall impose on any contractors retained to provide technical support or otherwise to assist with the implementation or administration of this Agreement or of the Open Access Transmission Tariff a contractual duty of confidentiality consistent with this Agreement. A Member shall not be obligated to provide confidential or proprietary information to any contractor that does not assume such a duty of confidentiality, and the Office of the Interconnection shall not provide any such information to any such contractor without the express written permission of the Member providing the information.

18.17.3 Disclosure to FERC and CFTC.

(a) Notwithstanding anything in this section to the contrary, if the FERC, the Commodity Futures Trading Commission ("CFTC"), or the staff of those commissions, during the course of an investigation or otherwise, requests information from the Office of the Interconnection that is otherwise required to be maintained in confidence pursuant to this Agreement, the Office of the Interconnection shall provide the requested information to the FERC, CFTC or their respective staff, within the time provided for in the request for information. In providing the information to the FERC or its staff, the Office of the Interconnection may request, consistent with 18 C.F.R. §§ 1b.20 and 388.112, or to the CFTC or its staff, the Office of the Interconnection may request, consistent with 17 C.F.R. §§ 11.3 and 145.9, that the information be treated as confidential and non-public by the respective commission and its staff and that the information be withheld from public disclosure. The Office of the Interconnection shall promptly notify any affected Member(s) if the Office of the Interconnection receives from the FERC, CFTC or their staff written notice that the commission has decided to release publicly, or has asked for comment on whether such commission should release publicly, confidential information previously provided to a commission by the Office of the Interconnection.

(b) Section 18.17.3(a) above shall not apply to requests for production of information under Subpart D of the FERC's Rules of Practice and Procedure (18 CFR Part 385) in proceedings before FERC and its administrative law judges. In all such proceedings, the Office of the Interconnection shall follow the procedures in section 18.17.2 above.

(c) Pursuant to the FERC Order No. 760, as codified under 18 C.F.R. § 35.28(g)(4), to the extent that the Office of the Interconnection already collects such data described in Order No. 760, the Office of the Interconnection shall electronically deliver to the FERC, on an ongoing basis and in a form and manner consistent with its own collection of data and in a form and manner acceptable to the FERC, data related to the markets that the Office of the Interconnection administers. Section 18.17.3(a) above shall not apply to data supplied to the FERC under this subsection (c) to satisfy the FERC Order No. 760 requirements.

(d) Pursuant to the FERC Order No. 771 and any clarifying orders, as codified under 18 C.F.R. § 366.2(d), the Office of the Interconnection shall ensure that FERC is included as an addressee on all e-Tags for transactions that sink within the PJM Region.

18.17.4 Disclosure to Authorized Commissions.

(a) Notwithstanding anything in this section to the contrary, the Office of the Interconnection shall disclose confidential information, otherwise required to be maintained in confidence pursuant to this Agreement, to an Authorized Commission under the following conditions:

(i) The Authorized Commission has provided the FERC with a properly-executed Certification in the form attached hereto as Operating Agreement, Schedule 10A. Upon receipt of the Authorized Commission's Certification, the FERC shall provide public notice of the Authorized Commission's filing pursuant to 18 C.F.R. § 385.2009. If any interested party disputes the accuracy and adequacy of the representations contained in the Authorized Commission's Certification, that party may file a protest with the Commission within 14 days of the date of such notice, pursuant to 18 C.F.R. § 385.211. The Authorized Commission may file a response to any such protest within seven days. Each party shall bear its own costs in connection with such a FERC protest proceeding. If there are material changes in law that affect the accuracy and adequacy of the representations in the Certification filed with the Commission, the Authorized Commission shall, within thirty (30) days, submit an amended Certification identifying such changes. Any such amended Certification shall be subject to the same procedures for comment and review by the Commission as set forth above in this paragraph.

The Office of the Interconnection may not disclose data to an Authorized Commission during the Commission's consideration of the Certification and any filed protests. If the Commission does not act upon an Authorized Commission's Certification within 90 days of the date of filing, the Certification shall be deemed approved and the Authorized Commission shall be permitted to receive confidential information pursuant to this section. In the event that an interested party protests the Authorized Commission's Certification and the Commission approves the Certification, that party may not challenge any Information Request made by the Authorized Commission on the grounds that the Authorized

Commission is unable to protect the confidentiality of the information requested, in the absence of a showing of changed circumstances.

(ii) Any confidential information provided to an Authorized Commission pursuant to this section shall not be further disclosed by the recipient Authorized Commission except by order of the Commission.

(iii) The Office of the Interconnection shall be expressly entitled to rely upon such Authorized Commission Certifications in providing confidential information to the Authorized Commission, and shall in no event be liable, or subject to damages or claims of any kind or nature hereunder, due to the ineffectiveness or inaccuracy of such Authorized Commission Certifications.

(iv) The Authorized Commission may provide confidential information obtained from the Office of the Interconnection to such of its employees, attorneys and contractors as needed to examine or handle that information in the course and scope of their work on behalf of the Authorized Commission, provided that (a) the Authorized Commission has internal procedures in place, pursuant to the Certification, to ensure that each person receiving such information agrees to protect the confidentiality of such information (such employees, attorneys or contractors to be defined hereinafter as "Authorized Persons"); (b) the Authorized Commission provides, pursuant to the Certification, a list of such Authorized Persons to the Office of the Interconnection and the Market Monitoring Unit and updates such list, as necessary, every ninety (90) days; and (c) any third-party contractors provided access to confidential information sign a non-disclosure agreement in the form attached hereto as Operating Agreement, Schedule 10 before being provided access to any such confidential information.

(v) The Office of the Interconnection shall maintain a schedule of all Authorized Persons and the Authorized Commissions they represent, which shall be made publicly available on its website, or by written request. Such schedule shall be compiled by the Office of the Interconnection, based on information provided by any Authorized Commission. The Office of the Interconnection shall update the schedule promptly upon receipt of information from an Authorized Commission, but shall have no obligation to verify or corroborate any such information, and shall not be liable or otherwise responsible for any inaccuracies in the schedule due to incomplete or erroneous information conveyed to and relied upon by the Office of the Interconnection in the compilation and/or maintenance of the schedule.

(b) The Office of the Interconnection may, in the course of discussions with an Authorized Person, orally disclose information otherwise required to be maintained in confidence, without

the need for a prior Information Request. Such oral disclosures shall provide enough information to enable the Authorized Person or the Authorized Commission with which that Authorized Person is associated to determine whether additional Information Requests are appropriate. The Office of the Interconnection will not make any written or electronic disclosures of confidential information to the Authorized Person pursuant to this section 18.17.4(b). In any such discussions, the Office of the Interconnection shall ensure that the individual or individuals receiving such confidential information are Authorized Persons as defined herein, orally designate confidential information that is disclosed, and refrain from identifying any specific Affected Member whose information is disclosed. The Office of the Interconnection shall also be authorized to assist Authorized Persons in interpreting confidential information that is disclosed. The Office of the Interconnection shall provide any Affected Member with oral notice of any oral disclosure immediately, but not later than one (1) Business Day after the oral disclosure. Such oral notice to the Affected Member shall include the substance of the oral disclosure, but shall not reveal any confidential information of any other Member and must be received by the Affected Member before the name of the Affected Member is released to the Authorized Person; provided however, disclosure of the identity of the Affected Party must be made to the Authorized Commission with which the Authorized Person is associated within two (2) Business Days of the initial oral disclosure.

(c) As regards Information Requests:

(i) Information Requests to the Office of the Interconnection and/or Market Monitoring Unit by an Authorized Commission shall be in writing, which shall include electronic communications, addressed to the Office of the Interconnection, and shall: (a) describe the information sought in sufficient detail to allow a response to the Information Request; (b) provide a general description of the purpose of the Information Request; (c) state the time period for which confidential information is requested; and (d) re-affirm that only Authorized Persons shall have access to the confidential information requested. The Office of the Interconnection shall provide an Affected Member with written notice, which shall include electronic communication, of an Information Request by an Authorized Commission as soon as possible, but not later than two (2) Business Days after the receipt of the Information Request.

(ii) Subject to the provisions of section (c)(iii) below, the Office of the Interconnection shall supply confidential information to the Authorized Commission in response to any Information Request within five (5) Business Days of the receipt of the Information Request, to the extent that the requested confidential information can be made available within such period; provided however, that in no event shall confidential information be released prior to the end of the fourth (4th) Business Day without the express consent of the Affected Member. To the extent that the Office of the Interconnection cannot reasonably prepare and deliver the requested confidential information within such five (5) day period, it shall, within such period, provide the Authorized Commission with a written schedule

for the provision of such remaining confidential information. Upon providing confidential information to the Authorized Commission, the Office of the Interconnection shall either provide a copy of the confidential information to the Affected Member(s), or provide a listing of the confidential information disclosed; provided, however, that the Office of the Interconnection shall not reveal any Member's confidential information to any other Member.

(iii) Notwithstanding section (c)(ii) above, should the Office of the Interconnection or an Affected Member object to an Information Request or any portion thereof, any of them may, within four (4) Business Days following the Office of the Interconnection's receipt of the Information Request, request, in writing, a conference with the Authorized Commission to resolve differences concerning the scope or timing of the Information Request; provided, however, nothing herein shall require the Authorized Commission to participate in any conference. Any party to the conference may seek assistance from FERC staff in resolution of the dispute or terminate the conference process at any time. Should such conference be refused or terminated by any participant or should such conference not resolve the dispute, then the Office of the Interconnection or the Affected Member may file a complaint with the Commission pursuant to Rule 206 objecting to the Information Request within ten (10) Business Days following receipt of written notice from any conference participant terminating such conference. Any complaints filed at FERC objecting to a particular Information Request shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding. The grounds for such a complaint shall be limited to the following: (a) the Authorized Commission is no longer able to preserve the confidentiality of the requested information due to changed circumstances relating to the Authorized Commission's ability to protect confidential information arising since the filing of or rejection of a protest directed to the Authorized Commission's Certification; (b) complying with the Information Request would be unduly burdensome to the complainant, and the complainant has made a good faith effort to negotiate limitations in the scope of the requested information; or (c) other exceptional circumstances exist such that complying with the Information Request would result in harm to the complainant. There shall be a presumption that "exceptional circumstances," as used in the prior sentence, does not include circumstances in which an Authorized Commission has requested wholesale market data (or Market Monitoring Unit workpapers that support or explain conclusions or analyses) generated in the ordinary course and scope of the operations of the Office of the Interconnection and/or the Market Monitoring Unit. There shall be a presumption that circumstances in which an Authorized Commission has requested personnel files, internal emails and internal company memos, analyses and related work product constitute "exceptional circumstances"

as used in the prior sentence. If no complaint challenging the Information Request is filed within the ten (10) day period defined above, the Office of the Interconnection shall utilize its best efforts to respond to the Information Request promptly. If a complaint is filed, and the Commission does not act on that complaint within ninety (90) days, the complaint shall be deemed denied and the Office of Interconnection shall use its best efforts to respond to the Information Request promptly.

(iv) Any Authorized Commission may initiate appropriate legal action at FERC within ten (10) Business Days following receipt of information designated as "Confidential," challenging such designation. Any complaints filed at FERC objecting to the designation of information as "Confidential" shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding. The party filing such a complaint shall be required to prove that the material disclosed does not merit "Confidential" status because it is publicly available from other sources or contains no trade secret or other sensitive commercial information (with "publicly available" not being deemed to include unauthorized disclosures of otherwise confidential data).

(d) In the event of any breach of confidentiality of information disclosed pursuant to an Information Request by an Authorized Commission or Authorized Person:

(i) The Authorized Commission or Authorized Person shall promptly notify the Office of the Interconnection, who shall, in turn, promptly notify any Affected Member of any inadvertent or intentional release, or possible release, of confidential information provided pursuant to this section.

(ii) The Office of the Interconnection shall terminate the right of such Authorized Commission to receive confidential information under this section upon written notice to such Authorized Commission unless: (i) there was no harm or damage suffered by the Affected Member; or (ii) similar good cause is shown. Any appeal of the Office of the Interconnection's and/or the Market Monitoring Unit's actions under this section shall be to FERC. An Authorized Commission shall be entitled to reestablish its certification as set forth in section 18.17.4(a) above by submitting a filing with the Commission showing that it has taken appropriate corrective action. If the Commission does not act upon an Authorized Commission's re-certification filing with sixty (60) days of the date of the filing, the re-certification shall be deemed approved and the Authorized Commission shall be permitted to receive confidential information pursuant to this section.

(iii) The Office of the Interconnection and/or the Affected Member shall have the right to seek and obtain at least the following types of relief: (a) an

order from FERC requiring any breach to cease and preventing any future breaches; (b) temporary, preliminary, and/or permanent injunctive relief with respect to any breach; and (c) the immediate return of all confidential information to the Office of the Interconnection.

(iv) No Authorized Person or Authorized Commission shall have responsibility or liability whatsoever under this section for any and all liabilities, losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with the release of confidential information to persons not authorized to receive it, provided that such Authorized Person is an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release. Nothing in this section (d)(iv) is intended to limit the liability of any person who is not an agent, servant, employee or member of an Authorized Commission at the time of such unauthorized release for any and all economic losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with such unauthorized release.

(v) Any dispute or conflict requesting the relief in section (d)(ii) or (d)(iii)(a) above, shall be submitted to FERC for hearing and resolution. Any dispute or conflict requesting the relief in section (d)(iii)(c) above may be submitted to FERC or any court of competent jurisdiction for hearing and resolution.

18.17.5 [Reserved]

18.17.6 Disclosure of EMS and Transmission System Data to Transmission Owners on PJM EMS Terminal and Via Other Reliability or Situational Awareness Tools

(a) While the Office of the Interconnection has overall responsibility for power system reliability in the PJM Region, Transmission Owners within the PJM Region perform specified reliability functions with respect to their individual Transmission Facilities and distribution systems. In order to facilitate reliable operations between the Office of the Interconnection and the Transmission Owners, the Office of the Interconnection may, without written authorization from any Member, install a read-only terminal, or allow the Transmission Owner through a secure communication channel, in any Transmission Owner's secure control room facility to access the Office of the Interconnection's Energy Management System (EMS), or its other reliability or situational awareness tools, and the associated transmission and generation data under the terms and conditions set forth in this section 18.17.6.

(b) The data and information produced by the EMS or other situational awareness tool, are confidential and/or commercially sensitive because they will display the real-time status of electric transmission lines and generation facilities, the disclosure of which could impact the market and the commercial interests of its participants. In addition, the responsive information will contain detailed information about real-time grid conditions, transmission lines, power

flows, and outages, which may fall within the definition of Critical Energy Infrastructure Information (CEII) as set forth in 18 CFR § 388.113. The Office of the Interconnection shall not release any generator cost, price or other market information without written authorization pursuant to section 18.17.1 (c) above unless otherwise provided for under this Agreement. The only generator information that will be made available on the read-only PJM EMS terminal is real-time MW/MVAR output and Minimum/Maximum MW Range. The transmission system information that may be made available via a reliability or situational awareness tool is limited to geospatial locations and other real-time operational data.

(c) The confidential or CEII information provided to the Transmission Owner on a read-only PJM EMS terminal or via another reliability or situational awareness tool shall only be held in the secure control room facility of the Transmission Owner. Such data shall be used for informational and operational purposes within the control room by transmission function employees as defined in the FERC's rules and regulations, 18 C.F.R. § 358. No "screen-scraping" or other data transfer of information from the read-only terminal or other situational awareness tool to other Transmission Owner systems or databases shall be permitted. No storage of information from the read-only terminal or other reliability or situational awareness tool shall be permitted. The data shall be held confidential within the transmission function environment and not be disclosed to other personnel within the Transmission Owners' company, subsidiaries, marketing organizations, energy affiliates or independent third parties. The Transmission Owner may use the confidential or CEII information only for the purpose of performing Transmission Owner's reliability function and shall not otherwise use the confidential information for its own benefit or for the benefit of any other person.

(d) In the event of any breach:

(i) The Transmission Owner(s) that caused the breach, or whose confidential information or CEII was used or disseminated beyond the limitations specified herein shall promptly notify the Office of the Interconnection, which shall, in turn, promptly notify FERC and any affected Member(s) of any inadvertent or intentional release, or possible release, of confidential or CEII information disclosed as provided above.

(ii) The Office of the Interconnection shall terminate all rights of the Transmission Owner to receive confidential or CEII information as provided in this section 18.17.6; provided, however, that the Office of the Interconnection may restore a Transmission Owners' status after consulting with the affected Member(s) whose confidential or CEII information was used or disseminated beyond the limitations specified herein and to the extent that: (a) the Office of the Interconnection determines that the disclosure was not due to the intentional, reckless or negligent action or omission of the authorized transmission function employee; (b) there were no harm or damages suffered by the affected Member(s); or (c) similar good cause shown. Any appeal of the Office of the Interconnection's actions under this section shall be to FERC.

(iii) The Office of the Interconnection and/or the affected Member(s) shall have the right to seek and obtain at least the following types of relief: (a) an order from FERC requiring any breach to cease and preventing any future breaches; (b) temporary, preliminary, and/or permanent injunctive relief and/or damages with respect to any breach; and (c) the immediate return of all confidential or CEII information to the Office of the Interconnection.

(iv) Any dispute or conflict requesting the relief in section (d)(ii) or (d)(iii)(a) above, shall be submitted to FERC for hearing and resolution. Any dispute or conflict requesting the relief in section (d)(iii)(b) and (c) above may be submitted to FERC or any court of competent jurisdiction for hearing and resolution.

18.17.7 Disclosure of Generator Data to Transmission Owners

(a) In order to facilitate reliable operations between the Office of the Interconnection and the Transmission Owners, the Office of the Interconnection may, without written authorization from any Member, provide to each Transmission Owner upon the Transmission Owner's request the following confidential generator information for any generator that: (1) is or will be modeled within the Transmission Owner's energy management system; or (2) is or will be identified in a Transmission Owner's restoration plan:

(i) real-time unit status;

(ii) real-time megawatt output;

(iii) real-time megavolt amperes reactive ("MVAR");

(iv) the start date, start time, stop date, and stop time for the unit's scheduled outages;

(v) the unit's reactive capability curve; and

(vi) data provided for Transmission Owner use for system restoration planning purposes only, including but not limited to the unit's start-up times, ramp rate, start-up auxiliary load profile and emergency low-load operation capabilities.

(b) In order to facilitate reliable operations between the Office of the Interconnection and the Transmission Owners, the Office of the Interconnection may, without written authorization from any Member, provide to each Transmission Owner the following generator information:

(i) forecasted unit status;

(ii) forecasted megawatt output;

(iii) the start date, start time, stop date, and stop time for the information in this section 18.17.7 (b)(i) and 18.17.7 (b)(ii);

(iv) the Zone in which the generator resides; and

(v) generator operating parameters including, but not limited, to each unit's start-up times, ramp rate, Minimum Down Time, and Minimum Run Time.

(c) The Office of the Interconnection will provide the data in section 18.17.7(a) and (b) only where it possesses such data. The Office of the Interconnection shall provide this confidential information only to transmission function employees, as transmission function employee is defined in section 18 C.F.R. § 358 of the FERC rules and regulations.

(d) A Transmission Owner may only use the generator data provided under section 18.17.7(a) and (b) above for the purpose of executing the Transmission Owner's reliability function and transmission function, as transmission function is defined in section 18 C.F.R. § 358 of the FERC rules and regulations, and shall not otherwise use the confidential information for its own benefit or the benefit of any other person. A Transmission Owner may disclose the generator data obtained under section 18.17.7(a) and (b) above only to the Transmission Owner's transmission function employees whose access to such data is necessary to perform the Transmission Owner's transmission functions. Transmission Owners shall not disclose the generator data obtained under section 18.17.7(a) and (b) above to any person, including marketing function employees as defined in section 18 C.F.R. § 358 of the FERC rules and regulations, except as permitted under this section 18.17.7.

(e) Each Transmission Owner shall protect and keep confidential all the information it receives from the Office of the Interconnection pursuant to this section 18.17.7. It may, copy, post, distribute, disclose or disseminate the data obtained pursuant to section 18.17.7(a) and (b) above only in the following manner. Each Transmission Owner may make a limited number of copies of written or electronic materials to enable the Transmission Owner to adequately use the information obtained pursuant to section 18.17.7(a) and (b) above within the terms and conditions of this section of this Agreement. If the Transmission Owner prints or electronically conveys any information in obtained pursuant to section 18.17.7(a) and (b) above, it shall protect each copy in accordance with this section 18.17.7 and mark each copy as "Confidential Information."

(f) The Transmission Owner shall destroy all information obtained under section 18.17.7(a) and (b) above upon the completion of the use of such information for the purpose of performing Transmission Owner's transmission functions, as transmission functions is defined in section 18 C.F.R. § 358 of the FERC rules and regulations.

(g) A Transmission Owner shall be responsible for the breach of this section 18.17.7 by any of its employees or representatives. In the event of any breach by the Transmission Owner of

this section 18.17.7 by any of its employees or representatives, section 18.17.6(d) shall apply to the release of the confidential information.

18.17.8 Disclosure of Credit-Related Information to FERC-Jurisdictional RTOs and ISOs

(a) Notwithstanding anything to the contrary in this Operating Agreement or in the Tariff, the Office of the Interconnection is permitted to share credit-related information of Members, Market Participants, and Applicants, including, without limitation, information of the respective Affiliates of the foregoing, with other FERC-jurisdictional RTOs and ISOs for the purpose of credit risk management and mitigation.

(b) The Office of the Interconnection is permitted to use credit-related information received from other FERC-jurisdictional RTOs and ISOs to the same extent and for the same purposes that it may use credit-related information received from its Members, Market Participants, and Applicants. The Office of the Interconnection will treat credit-related information received from other FERC-jurisdictional RTOs and ISOs as confidential information to the same extent as it would treat such information if it were received directly from one of its Members, Market Participants or Applicants.

1.10 Scheduling.

1.10.1 General.

(a) The Office of the Interconnection shall administer scheduling processes to implement a Day-ahead Energy Market and a Real-time Energy Market. PJMSettlement shall be the Counterparty to the purchases and sales of energy that clear the Day-ahead Energy Market and the Real-time Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a Generating Market Buyer's self-schedule or self-supply of its generation resources up to that Generating Market Buyer's Equivalent Load.

(b) The Day-ahead Energy Market shall enable Market Participants to purchase and sell energy through the PJM Interchange Energy Market at Day-ahead Prices and enable Transmission Customers to reserve transmission service with Transmission Congestion Charges and Transmission Loss Charges based on locational differences in Day-ahead Prices. Up-to Congestion Transactions submitted in the Day-ahead Energy Market shall not require transmission service and Transmission Customers shall not reserve transmission service for such Up-to Congestion Transactions. Market Participants whose purchases and sales, and Transmission Customers whose transmission uses are scheduled in the Day-ahead Energy Market, shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, at the applicable Day-ahead Prices for the amounts scheduled.

(c) (i) In the Real-time Energy Market, Market Participants that deviate from the amounts of energy purchases or sales scheduled in the Day-ahead Energy Market shall be obligated to purchase or sell energy for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(ii) In the Real-time Energy Market, Transmission Customers that deviate from the transmission uses, scheduled in the Day-ahead Energy Market shall be obligated to pay Transmission Congestion Charges and Transmission Loss Charges for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(iii) Market Participants that deviate in real-time from the amounts of Secondary Reserve, Non-Synchronized Reserve, or Synchronized Reserve sales, scheduled day-ahead shall be obligated to purchase Secondary Reserve, Non-Synchronized Reserve, or Synchronized Reserve for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly

energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling does not encompass Coordinated External Transactions, which are subject to the procedures of Operating Agreement, Schedule 1, section 1.13. Scheduling shall be conducted as specified in section 1.10.1A below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM Manuals. Such resources committed by the Office of the Interconnection to alleviate or mitigate an Emergency will not receive energy uplift Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Operating Agreement, Schedule 1, section 3.2.3 and Operating Agreement, Schedule 1, section 6.6.

(e) To the extent that Tariff, Attachment K-Appendix, sections 3.2.3A, 3.2.3A.001, and 3.2.3A.01 and the parallel provision of Operating Agreement, Schedule 1, sections 3.2.3A, 3.2.3A.001, and 3.2.3A.01 does not meet the Minimum Synchronized Reserve Requirement, the Minimum Primary Reserve Requirement, and the Minimum 30-minute Reserve Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Tariff, Attachment K-Appendix, section 1.7.17 and the parallel provision of Operating Agreement, Schedule 1, section 1.7.17, and Tariff, Attachment K-Appendix, section 1.10 and the parallel provision of Operating Agreement, Schedule 1, section 1.10. In addition, the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the day-ahead market.

1.10.1A Day-ahead and Real-time Energy Market Scheduling.

The following actions shall occur not later than 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the Office of the Interconnection in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Schedule.

(a) Each Market Participant may submit to the Office of the Interconnection specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the PJM Manuals. Each Market Buyer shall inform the Office of the Interconnection of the prices, if any, at which it desires not to include its load in the Day-ahead Energy Market rather than pay the Day-ahead Price. PRD Providers that have committed Price Responsive Demand in accordance with the Reliability Assurance Agreement shall submit to the Office of the Interconnection, in accordance with procedures specified in the PJM Manuals, any desired updates to their previously submitted PRD Curves, provided that such updates are consistent with their Price Responsive Demand commitments, and provided further that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue

may only submit PRD Curves for the Real-time Energy Market. Price Responsive Demand that has been committed in accordance with the Reliability Assurance Agreement shall be presumed available for the next Operating Day in accordance with the most recently submitted PRD Curve unless the PRD Curve is updated to indicate otherwise. PRD Providers may also submit PRD Curves for any Price Responsive Demand that is not committed in accordance with the Reliability Assurance Agreement; provided that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue may only submit PRD Curves for the Real-time Energy Market. All PRD Curves shall be on a PRD Substation basis, and shall specify the maximum time period required to implement load reductions.

(b) Each Generating Market Buyer shall submit to the Office of the Interconnection: (i) hourly schedules for resource increments, including hydropower units, self-scheduled by the Market Buyer to meet its Equivalent Load; and (ii) the Dispatch Rate at which each such self-scheduled resource will disconnect or reduce output, or confirmation of the Market Buyer's intent not to reduce output.

(c) All Market Participants shall submit to the Office of the Interconnection schedules for any energy exports, energy imports, and wheel through transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection if the transaction is to be scheduled in the Day-ahead Energy Market. Any Market Participant that elects to schedule an export, import or wheel through transaction in the Day-ahead Energy Market may specify the price (such price not to exceed $2,000/MWh), if any, at which the export, import or wheel through transaction will be wholly or partially curtailed. The foregoing price specification shall apply to the applicable interface pricing point. Any Market Participant that elects not to schedule its export, import or wheel through transaction in the Day-ahead Energy Market shall inform the Office of the Interconnection if the parties to the transaction are not willing to incur Transmission Congestion and Loss Charges in the Real-time Energy Market in order to complete any such scheduled transaction. Such transactions in the Real-time Energy Market, other than Coordinated Transaction Schedules and emergency energy sales and purchases, may specify a price up to $2,000/MWh. Scheduling of such transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

i) Market Participants shall submit schedules for all energy purchases for delivery within the PJM Region, whether from resources inside or outside the PJM Region;

ii) Market Participants shall submit schedules for exports for delivery outside the PJM Region from resources within the PJM Region that are not Dynamic Transfers to such entities pursuant to Operating Agreement, Schedule 1, section 1.12; and

iii) In addition to the foregoing schedules for exports, imports and wheel through transactions, Market Participants shall submit confirmations of each scheduled transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(c-1) A Market Participant may elect to submit in the Day-ahead Energy Market a form of Virtual Transaction that combines an offer to sell energy at a source, with a bid to buy the same megawatt quantity of energy at a sink where such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink. The Office of Interconnection will schedule these transactions only to the extent this difference in Locational Marginal Prices is within the maximum amount specified by the Market Participant. A Virtual Transaction of this type is referred to as an "Up-to Congestion Transaction." Such Up-to Congestion Transactions may be wholly or partially scheduled depending on the price difference between the source and sink locations in the Day-ahead Energy Market. The maximum difference between the source and sink prices that a participant may specify shall be limited to +/- $50/MWh. The foregoing price specification shall apply to the price difference between the specified source and sink in the day-ahead scheduling process only. An accepted Up-to Congestion Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-ahead Energy Market.

(c–2) A Market Participant may elect to submit an Increment Offer and/or Decrement Bid form of Virtual Transaction in the Day-ahead Energy Market and shall specify the price for such transaction which shall be limited to $2,000/megawatt-hour.

(c-3) Up-to Congestion Transactions may only be submitted at hubs, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b). Increment Offers and Decrement Bids may be only submitted at hubs, nodes at which physical generation or load is settled, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b).

(d) Market Sellers in the Day-ahead Energy Market shall submit offers for the supply of energy, demand reductions, or other services for the following Operating Day for each clock hour for which the Market Seller desires or is required to make its resource available to the Office of the Interconnection. Offers for the supply of energy may be cost-based, market-based, or both, and may vary hourly. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, Operating Agreement, Schedule 2, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that is committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. Such offers shall be based on the ICAP equivalent of the Market Seller's cleared UCAP capacity commitment, provided, however, (i) where the underlying resource is a Capacity Storage Resource, with the exception of Capacity Storage Resource participating in the Energy Storage Resource Participation Model, or an Intermittent Resource, the Market Seller shall satisfy the must offer requirement by either self-scheduling or offering the unit as a dispatchable resource, in accordance with the PJM Manuals, where the hourly day-ahead self-scheduled values for such Capacity Storage Resources and Intermittent Resources may vary hour to hour

from the capacity commitment, and (ii) where the underlying resource is a Hybrid Resource or Capacity Storage Resource participating in the Energy Storage Resource Participation Model, the Market Seller shall satisfy the must offer requirement by self-scheduling the unit in accordance with the PJM Manuals, where the hourly day-ahead self-scheduled values for such Hybrid Resource or Capacity Storage Resource may vary hour to hour from the capacity commitment. Any offer not designated as a Maximum Emergency offer shall be considered available for scheduling and dispatch under both Emergency and non-Emergency conditions. Offers may only be designated as Maximum Emergency offers to the extent that the Generation Capacity Resource falls into at least one of the following categories:

i) Environmental limits. If the resource has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited to operating only during declared PJM capacity emergencies by a governmental authority.

ii) Fuel limits. If physical events beyond the control of the resource owner result in the temporary interruption of fuel supply and there is limited on-site fuel storage. A fuel supplier's exercise of a contractual right to interrupt supply or delivery under an interruptible service agreement shall not qualify as an event beyond the control of the resource owner.

iii) Temporary emergency conditions at the unit. If temporary emergency physical conditions at the resource significantly limit its availability.

iv) Temporary megawatt additions. If a resource can provide additional megawatts on a temporary basis by oil topping, boiler over-pressure, or similar techniques, and such megawatts are not ordinarily otherwise available.

The submission of offers for resource increments that are not committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1 shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2, and the PJM Manuals, as applicable. Energy offered from generation resources that are not committed as a Capacity Resource under Tariff, Attachment DD or RAA, Schedule 8.1 shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region.

The foregoing offers:

i) Shall specify the Generation Capacity Resource or Economic Load Response Participant resource and energy or demand reduction amount, respectively, for each clock hour in the offer period;

ii) Shall specify the amounts and prices for each clock hour during the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;

iii) May specify for generation resources offer parameters for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) Minimum Run Time; (2) maximum run time; (3) Start-up Costs; (4) No-load Costs; (5) Incremental Energy Offer; (6) notification time; (7) availability; (8) ramp rate; (9) Economic Minimum; (10) Economic Maximum; (11) emergency minimum MW; (12) emergency maximum MW; (13) Synchronized Reserve maximum MW; (14) Secondary Reserve maximum MW; and (15) condense to generation time constraints, and may specify offer parameters for Economic Load Response Participant resources for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) minimum down time; (2) maximum down time; (3) minimum release time; (4) shutdown costs; (5) Incremental Energy Offer; (6) notification time; (7) Economic Minimum; and (8) Economic Maximum;

iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;

v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with additional schedules applicable if accepted after the foregoing deadline;

vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer for the clock hour, which offer shall remain open through the Operating Day, for which the offer is submitted, unless the Market Seller a) submits a Real-time Offer for the applicable clock hour, or b) updates the availability of its offer for that hour, as further described in the PJM Manuals;

vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day, unless modified after the close of the Day-ahead Energy Market as permitted pursuant to sections 1.10.9A or 1.10.9B below;

viii) Shall not exceed an energy offer price of $1,000/megawatt-hour for all generation resources, except (1) when a Market Seller's cost-based offer is

above $1,000/megawatt-hour and less than or equal to $2,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer; and (2) when a Market Seller's cost-based offer is greater than $2,000/megawatt-hour, then its market-based offer must be less than or equal to $2,000/megawatt-hour;

ix) Shall not exceed a demand reduction offer price of $1,000/megawatt-hour, except when an Economic Load Response Participant submits a cost-based offer that includes an incremental cost component that is above $1,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer but in no event greater than $2,000/megawatt-hour;

x) Shall not exceed an offer price as follows for Emergency Load Response and Pre-Emergency Load Response participants with:

a) a 30 minute lead time, pursuant to Tariff, Attachment DD-1, section A.2 and the parallel provision of RAA, Schedule 6, $1,000/megawatt-hour, plus the applicable Reserve Penalty Factor for the Primary Reserve Requirement, minus $1.00;

b) an approved 60 minute lead time, pursuant to Tariff, Attachment DD-1, section A.2 and the parallel provision of RAA, Schedule 6, $1,000/megawatt-hour, plus [the applicable Reserve Penalty Factor for the Primary Reserve Requirement divided by 2]; and

c) an approved 120 minute lead time, pursuant to Tariff, Attachment DD-1, section A.2 and the parallel provisions of RAA, Schedule 6, $1,100/megawatt-hour; and

xi) Shall not exceed an energy offer price of $0.00/MWh for pumped storage hydropower units scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation for each 30 minute Regulation clearing interval for which the Market Seller desires to make its resource available to the Office of the Interconnection to provide Regulation that shall specify the megawatts of Regulation being offered, which must equal or exceed 0.1 megawatts, in the Regulation Zone for which such Regulation is offered, the price of the capability offer in dollars per MW, the price of the mileage offer in Dollars per change in MW, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the resource's opportunity costs. Such offers may vary for each 30 minute Regulation clearing interval, and may be updated each 30 minute Regulation clearing interval, up to 35 minutes before the applicable 30 minute Regulation clearing interval during the Operating Day. The total of the mileage offer multiplied by the historical average mileage used in the market clearing plus the capability offer shall not exceed $100/megawatt-

hour. In addition to any market-based offer for Regulation, the Market Seller also shall submit a cost-based offer. A cost-based offer must be in the form specified in the PJM Manuals and consist of the following components as well as any other components specified in the PJM Manuals:

i. The costs (in $/MW) of the fuel cost increase due to the steady-state heat rate increase resulting from operating the unit at lower megawatt output incurred from the provision of Regulation shall apply to the capability offer;

ii. The cost increase (in $/ΔMW) in costs associated with movement of the regulation resource incurred from the provision of Regulation shall apply to the mileage offer; and

a. Only Regulation-only resources may include all variable operation and maintenance expenses in the mileage offer, as defined in the PJM Manuals.

iii. An adder of up to $12.00 per megawatt of Regulation provided applied to the capability offer.

Qualified Regulation capability must satisfy the measurement and verification tests specified in the PJM Manuals.

(f) Each Market Seller owning or controlling the output of a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative shall submit a forecast of the availability of each such Generation Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with Start-up Costs and No-load Costs, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours. Such resources committed by the Office of the Interconnection will not receive energy uplift Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Operating Agreement, Schedule 1, section 3.2.3 and Operating Agreement, Schedule 1, section 6.6.

(g) Each component of an offer by a Market Seller of a Generation Capacity Resource that is constant for the entire Operating Day and does not vary hour to hour shall remain in effect for subsequent Operating Days until superseded or canceled.

(h) The Office of the Interconnection shall post the total hourly loads scheduled in the Day-ahead Energy Market, as well as, its estimate of the combined hourly load of the Market Buyers for the next four days, and peak load forecasts for an additional three days.

(i) Except for Economic Load Response Participants, all Market Participants may submit Virtual Transactions that apply to the Day-ahead Energy Market only. Such Virtual Transactions must comply with the requirements set forth in the PJM Manuals and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-ahead Energy Market. The Office of the Interconnection may require that a market participant shall not submit in excess of a defined number of bid/offer segments in the Day-ahead Energy Market, as specified in the PJM Manuals, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to 10:00 a.m. EPT on the day that the Day-ahead Energy Market will clear. For purposes of this provision, a bid/offer segment is each pairing of price and megawatt quantity submitted as part of an Increment Offer or Decrement Bid. For purposes of applying this provision to an Up-to Congestion Transaction, a bid/offer segment shall refer to the pairing of a source and sink designation, as well as price and megawatt quantity, that comprise each Up-to Congestion Transaction.

(j) (i) Offers to Supply Synchronized and Non-Synchronized Reserves By Generation Resources in the Day-ahead and Real-time Reserve Markets

(1) Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Tariff, Attachment DD, is capable of providing Synchronized Reserve or Non-Synchronized Reserve as specified in section 1.7.19A(a), in section 1.7.19A.01(a) and in the PJM Manuals, and has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage, shall submit offers or otherwise make their 10-minute reserve capability available to supply Synchronized Reserve or, as applicable, Non-Synchronized Reserve, including any portion that is self-scheduled by the Generating Market Buyer, in an amount equal to the available 10-minute reserve capability of such Generation Capacity Resource. Market Sellers of Generation Capacity Resources subject to this must-offer requirement that do not make the reserve capability of such resources available when such resource is able to operate with a dispatchable range (e.g. through offering a fixed output) will be in violation of this provision.

(2) Market Sellers of all other generation resources that (A) are capable of providing Synchronized Reserve or Non-Synchronized Reserve, as specified in section 1.7.19A(a), in section 1.7.19A.01(a) and in the PJM Manuals, (B) are located within the metered boundaries of the PJM Region, and (C) have submitted offers for the supply of energy into the Day-ahead Energy Market and/or Real-time Energy Market shall be deemed to have made their reserve capability available to provide Synchronized Reserve or Non-Synchronized Reserve in the Day-ahead Energy Market and/or Real-time Energy Market for each clock hour for which the Market Seller submits an available offer to supply energy; provided, however that hydroelectric generation resources and Energy Storage Resources

are not automatically deemed available to provide reserves based on the submission of an available energy offer but may submit offers to supply Synchronized Reserve and Non-Synchronized Reserve, as applicable.

(3) Offers for the supply of Synchronized Reserve by all generation resources must be cost-based. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A, section 1.10.9B below, and the PJM Manuals, as applicable. For offers to supply Synchronized Reserve, the offer price shall not exceed the expected value of the penalty for failing to provide Synchronized Reserve, where such expected value shall be recalculated annually, in accordance with the PJM Manuals, and posted on PJM's website. The expected value of the penalty is calculated as the product of: (A) the average penalty, expressed in $/MWh, multiplied by (B) the average rate of non-performance during Synchronized Reserve events multiplied by (C) the probability a Synchronized Reserve event that will qualify for non-performance assessments will occur.

The expected value of the penalty shall be determined by an annual review of the twelve-month period ending October 31 of the calendar year in which the review is performed. The Office of the Interconnection shall post the results of its annual review by no later than December 15, and the revised offer price cap shall be effective as of the following January 1; provided, however, that at the time of implementation of this rule the expected value of the penalty shall be $0.02/MWh, and for the period from the second month after implementation through the second December 31 following such date of implementation, the expected value of the penalty shall be recalculated on a monthly basis using data from the implementation date of this rule through the 15th day of the current month, and the revised value shall be effective the 1st day of the following month.

(4) All Non-Synchronized Reserve offers shall be for $0.00/MWh. Consistent with the resource's offer to supply energy, such offers may vary hourly and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this subsection (d) of this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

(ii) Determination of Available Synchronized Reserve Capability of Generation Resources

(1) For each offer to supply reserves by a synchronized resource, the Office of the Interconnection shall determine the MW of available Synchronized Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market, in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Hydroelectric generation resources and Energy Storage Resources may submit offers for their available Synchronized Reserve capability as part of their offer into the Synchronized Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(j)(i) above must submit a Synchronized Reserve offer which specifies the MW of available Synchronized Reserve capability in order to remain compliant with such requirements.

(2) An on-line generation resource's available Synchronized Reserve capability, except for generation resources capable of synchronous condensing, shall be determined in accordance with the PJM Manuals and based on the resource's current performance and initial energy output and the following offer parameters submitted as part of the resource's energy offer: (A) ramp rate; (B) Economic Minimum; and (C) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Synchronized Reserves above the Synchronized Reserve maximum MW.

For generation resources capable of synchronous condensing, the resource's available Synchronized Reserve capability shall be based on the following offer parameters submitted as part of the resource's energy offer: (D) ramp rate; (E) condense to generation time constraints; (F) Economic Minimum; and (G) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Synchronized Reserves above the Synchronized Reserve maximum MW.

(3) Any Market Seller that believes its generating unit has operating modes, limits, or conditions where the unit would not be capable of providing Synchronized Reserves in real time, can submit to the Office of the Interconnection with a copy to the Market Monitoring Unit a request for an exception from being assigned Synchronized Reserves in the Real-time Synchronized Reserve Market during time periods in which the generating unit is in those operating modes, limits, or conditions. As part of the request, the Market

Seller shall supply, for each generating unit, technical information about the operational modes, limits, or conditions to support the requested exception, as further detailed in the PJM Manuals. The Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a request for such an exception. Within 60 days of the submission of the request, the Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, whether the request is approved or denied. The effective date of any approved request will be provided in the written notification. If a Market Seller has an approved exception, the Market Seller must communicate to the Office of the Interconnection when the unit cannot provides reserves, and the Office of the Interconnection will provide a mechanism for Market Sellers with an approved exception to provide such communication to the Office of the Interconnection in real time, as further detailed in the PJM Manuals. An approved exception will remain applicable to the unit until such time as the Office of the Interconnection determines that a change is needed or the Market Seller notifies the Office of the Interconnection, with a copy to the Market Monitoring Unit, that a change is needed based on changed operational capabilities of the unit. Market Sellers must notify the Office of the Interconnection, with a copy to the Market Monitoring Unit, within 30 days of any changed operational capabilities that necessitate a change in an approved exception.

(iii) Determination of Available Non-Synchronized Reserve Capability of Generation Resources

(1) For each offer to supply reserves by an off-line generation resource, the Office of the Interconnection shall determine the MW of available Non-Synchronized Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Such hydroelectric generation resources or Energy Storage Resources may submit offers for their available Non-Synchronized Reserve capability as part of their offer into the Non-Synchronized Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(j)(i) above must submit a Non-Synchronized Reserve offer which specifies the MW of available Non-Synchronized Reserve capability in order to remain compliant with such requirements.

(2) An off-line generation resource's available Non-Synchronized Reserve capability shall be determined in accordance with the PJM Manuals and based on the following offer parameters submitted as part of the resource's energy offer: (A) startup time; (B) notification time; (C) ramp rate; (D) Economic Minimum; and (E) the lesser of Economic Maximum and Synchronized Reserve maximum MW, where Synchronized Reserve maximum MW may be lower than the

Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Non-Synchronized Reserves above its Synchronized Reserve maximum MW.

(iv) Offers to Supply Synchronized Reserves by Economic Load Response Participant Resources in the Day-ahead and Real-time Reserve Markets

(1) Economic Load Response Participants that submit offers to reduce demand into the Day-ahead Energy Market and Real-time Energy Market and wish to make their resources available to supply Synchronized Reserve may submit offers to supply Synchronized Reserve from such resources, where such offers shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.1 megawatts and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day.

(2) All offers to supply Synchronized Reserve offers from Economic Load Response Participant resources shall not exceed the expected value of the penalty for failing to provide Synchronized Reserve, as determined in accordance with section 1.10.1A(j)(i)(3) above. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

(k) An Economic Load Response Participant that wishes to participate in the Day-ahead Energy Market by reducing demand shall submit an offer to reduce demand to the Office of the Interconnection for each clock hour for which the Economic Load Response Participant desires to make its resource available to the Office of the Interconnection to reduce demand. The offer must equal or exceed 0.1 megawatts, may vary hourly, and shall specify: (i) the amount of the offered curtailment in minimum increments of .1 megawatts: (ii) the Day-ahead Locational Marginal Price above which the end-use customer will reduce load, subject to section 1.10.1A(d)(ix); and (iii) at the Economic Load Response Participant's option, shutdown costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum of number of contiguous hours for which the load reduction must be committed. Such offers may be updated each hour, up to 65 minutes before the applicable clock hour during the Operating Day. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs) per hour.

(l) Market Sellers owning or controlling the output of an Economic Load Response Participant resource that was committed in an FRR Capacity Plan, or that was self-supplied or that offered and cleared in a Base Residual Auction or Incremental Auction, may submit demand

reduction bids for the available load reduction capability of the Economic Load Response Participant resource. The submission of demand reduction bids for Economic Load Response Participant resource increments that were not committed in an FRR Capacity Plan, or that have not cleared in a Base Residual Auction or Incremental Auction, shall be optional, but any such bids must contain the information required to be included in such bids, as specified in the PJM Economic Load Response Program. An Economic Load Response Participant resource that was committed in an FRR Capacity Plan, or that was self-supplied or offered and cleared in a Base Residual Auction or Incremental Auction, may submit a demand reduction bid in the Day-ahead Energy Market as specified in the Economic Load Response Program; provided, however, that in the event of an Emergency PJM shall require Economic Load Response Participant resources to reduce load, notwithstanding that the Zonal LMP at the time such Emergency is declared is below the price identified in the demand reduction bid.

(m) (i) Offers to Supply Secondary Reserve By Generation Resources

(1) Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Tariff, Attachment DD, that is available for energy, is capable of providing Secondary Reserve, as specified in section 1.7.19A.02(a) and in the PJM Manuals, and has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers to supply Secondary Reserve, or otherwise make their Secondary Reserve capability available. Such offers shall be for an amount equal to the resource's available energy output achievable within thirty minutes (less its energy output achievable within ten minutes) from a request of the Office of the Interconnection. Market Sellers of Generation Capacity Resources subject to this must-offer requirement that do not make the reserve capability of such resources available when such resource is able to operate with a dispatchable range (e.g. through offering a fixed output) will be in violation of this provision.

(2) Market Sellers of all other generation resources located within the metered boundaries of the PJM Region that submit offers for the supply of energy into the Day-ahead Energy Market and/or Real-time Energy Market and are capable of providing Secondary Reserve, as specified in the PJM Manuals, shall be deemed to have made their reserve capability available to provide Secondary Reserve in the Day-ahead Energy Market and/or Real-time Energy Market for each clock hour for which the Market Seller submits an available offer to supply energy; provided, however that hydroelectric generation resources and Energy Storage Resources are not automatically deemed available to provide reserves based on the submission of an available energy offer but may submit offers to supply Secondary Reserve, as applicable.

(3) Offers for the supply of Secondary Reserve shall be for $0.00/MWh. Consistent with the resource's offer to supply energy, such offers may vary hourly

and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this subsection (d) above, section 1.10.9B below, and the PJM Manuals, as applicable.

(ii) Determination of Available Secondary Reserve Capability of Generation Resources

(1) For each offer to supply Secondary Reserve by a generation resource, the Office of the Interconnection shall determine the MW of available Secondary Reserve capability offered in the Day-ahead Energy Market and Real-time Energy Market in accordance with the PJM Manuals; except, however, that the Office of the Interconnection will not make such determination for hydroelectric generation resources or Energy Storage Resources. Hydroelectric generation resources or Energy Storage Resources may submit their available Secondary Reserve capability as part of their offer into the Secondary Reserve market, provided that such offer equals or exceeds 0.1 MW; however, any such resource which is subject to the must offer requirements in section 1.10.1A(m)(i) above must submit a Secondary Reserve offer which specifies the MW of available Secondary Reserve capability in order to remain compliant with such requirements.

(2) (A) An on-line generation resource's available Secondary Reserve capability, except for generation resources capable of synchronous condensing, shall be based on the resource's current performance and initial energy output, the resource's available Synchronized Reserve capability; and the following offer parameters submitted as part of the energy offer: (i) ramp rate; (ii) Economic Minimum; and (iii) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(B) For generation resources capable of synchronous condensing, the resource's available Secondary Reserve capability shall be based on the following offer parameters submitted as part of the energy offer: (i) ramp rate; (ii) condense to generation time constraints; (iii) Economic Minimum; and (iv) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that

the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(C) An off-line generation resource's available Secondary Reserve capability, shall be based on the resource's available Secondary Reserve capability and the following offer parameters submitted as part of the resource's energy offer: (i) startup time; (ii) notification time; (iii) ramp rate; (iv) Economic Minimum; and (v) the lesser of Economic Maximum and Secondary Reserve maximum MW, where a resource's Secondary Reserve maximum MW may be less than the Economic Maximum only where the Market Seller has, in accordance with the procedures set forth in the PJM Manuals, submitted justification to the Office of the Interconnection that the resource has an operating configuration that prevents it from reliably providing Secondary Reserves above its Secondary Reserve maximum MW.

(3) Any Market Seller that believes its generating unit has operating modes, limits, or conditions where the unit would not be capable of providing Secondary Reserves in real time, can submit to the Office of the Interconnection with a copy to the Market Monitoring Unit a request for an exception from being assigned Secondary Reserves in the Real-time Secondary Reserve Market during time periods in which the generating unit is in those operating modes, limits, or conditions. As part of the request, the Market Seller shall supply, for each generating unit, technical information about the operational modes, limits, or conditions to support the requested exception, as further detailed in the PJM Manuals. The Office of the Interconnection shall consult with the Market Monitoring Unit, and consider any input received from the Market Monitoring Unit, in its determination of a request for such an exception. Within 60 days of the submission of the request, the Office of the Interconnection shall notify the Market Seller in writing, with a copy to the Market Monitoring Unit, whether the request is approved or denied. The effective date of any approved request will be provided in the written notification. If a Market Seller has an approved exception, the Market Seller must communicate to the Office of the Interconnection when the unit cannot provides reserves, and the Office of the Interconnection will provide a mechanism for Market Sellers with an approved exception to provide such communication to the Office of the Interconnection in real time, as further detailed in the PJM Manuals. An approved exception will remain applicable to the unit until such time as the Office of the Interconnection determines that a change is needed or the Market Seller notifies the Office of the Interconnection, with a copy to the Market Monitoring Unit, that a change is needed based on changed operational capabilities of the unit. Market Sellers must notify the Office of the Interconnection, with a copy to the Market Monitoring

Unit, within 30 days of any changed operational capabilities that necessitate a change in an approved exception.

(iii) Offers to Supply Secondary Reserves by Economic Load Response Participant resources

(1) Each Economic Load Response Participant that submits offers to reduce demand into the Day-ahead Energy Market and Real-time Energy Market and wishes to make their resources available to supply Secondary Reserve shall submit offers to supply Secondary Reserve from such resources, where such offers shall specify the megawatts of Secondary Reserve being offered, which must equal or exceed 0.1 megawatts and include such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day.

(2) All Secondary Reserve offers by Economic Load Response Participant resources shall be for $0.00/MWh. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this section 1.10.1A(d), section 1.10.9B below, and the PJM Manuals, as applicable.

(n) A Market Participant may submit a Day-Ahead Pseudo-Tie Transaction for a Market Participant's generator within the PJM balancing authority area that is a Pseudo-Tie into the MISO balancing authority area. Day-Ahead Pseudo-Tie Transactions combine an offer to sell energy at a source with a bid to buy the same megawatt quantity of energy at a sink where such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink.

Each Day-Ahead Pseudo-Tie Transaction shall: (1) source at a Market Participant's generator within the PJM balancing authority area that Pseudo-Ties into MISO; and (2) sink at the PJM-MISO interface. A Market Participant must reserve transmission service in accordance with the PJM Tariff for each Day-Ahead Pseudo-Tie Transaction. Megawatt quantities for Day-Ahead Pseudo-Tie Transactions shall be greater than zero and less than or equal to the transmission service reserved for the Day-Ahead Pseudo-Tie Transaction. An accepted Day-Ahead Pseudo-Tie Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-Ahead Energy Market.

1.10.1B Demand Bid Scheduling and Screening

(a) The Office of the Interconnection shall apply Demand Bid Screening to all Demand Bids submitted in the Day-ahead Energy Market for each Load Serving Entity, separately by Zone. Using Demand Bid Screening, the Office of the Interconnection will automatically reject a Load Serving Entity's Demand Bids in any future Operating Day for which the Load Serving Entity

submits bids if the total megawatt volume of such bids would exceed the Load Serving Entity's Demand Bid Limit for any hour in such Operating Day, unless the Office of the Interconnection permits an exception pursuant to subsection (d) below.

(b) On a daily basis, PJM will update and post each Load Serving Entity's Demand Bid Limit in each applicable Zone. Such Demand Bid Limit will apply to all Demand Bids submitted by that Load Serving Entity for each future Operating Day for which it submits bids. The Demand Bid Limit is calculated using the following equation:

Demand Bid Limit = greater of (Zonal Peak Demand Reference Point * 1.3), or (Zonal Peak Demand Reference Point + 10MW)

Where:

1. Zonal Peak Demand Reference Point = for each Zone: the product of (a) LSE Recent Load Share, multiplied by (b) Peak Daily Load Forecast.
2. LSE Recent Load Share is the Load Serving Entity's highest share of Network Load in each Zone for any hour over the most recently available seven Operating Days for which PJM has data.
3. Peak Daily Load Forecast is PJM's highest available peak load forecast for each applicable Zone that is calculated on a daily basis.

(c) A Load Serving Entity whose Demand Bids are rejected as a result of Demand Bid Screening may change its Demand Bids to reduce its total megawatt volume to a level that does not exceed its Demand Bid Limit, and may resubmit them subject to the applicable rules related to bid submission outlined in Tariff, Operating Agreement and PJM Manuals.

(d) PJM may allow a Load Serving Entity to submit bids in excess of its Demand Bid Limit when circumstances exist that will cause, or are reasonably expected to cause, a Load Serving Entity's actual load to exceed its Demand Bid Limit on a given Operating Day. Examples of such circumstances include, but are not limited to, changes in load commitments due to state sponsored auctions, mergers and acquisitions between PJM Members, and sales and divestitures between PJM Members. A Load Serving Entity may submit a written exception request to the Office of Interconnection for a higher Demand Bid Limit for an affected Operating Day. Such request must include a detailed explanation of the circumstances at issue and supporting documentation that justify the Load Serving Entity's expectation that its actual load will exceed its Demand Bid Limit.

1.10.2 Pool-scheduled Resources.

Pool-scheduled resources are those resources for which Market Participants submitted offers to sell energy in the Day-ahead Energy Market and offers to reduce demand in the Day-ahead Energy Market, which the Office of the Interconnection scheduled in the Day-ahead Energy Market as well as generators committed by the Office of the Interconnection subsequent to the Day-ahead Energy Market. Such resources shall be committed to provide energy in the real-time dispatch unless the schedules for such units are revised pursuant to section 1.10.9 below or

Operating Agreement, Schedule 1, section 1.11. Pool-scheduled resources shall be governed by the following principles and procedures.

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, whether the resource is expected to be needed to maintain system reliability during the Operating Day, Start-up Costs, No-load Costs, and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in section 1.10.1A above. Hydropower units can only be pool-scheduled if they are pumped storage units and scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

(b) A resource that is scheduled by a Market Participant to support a bilateral sale, or that is self-scheduled by a Generating Market Buyer, shall not be selected by the Office of the Interconnection as a pool-scheduled resource except in an Emergency.

(c) Market Sellers offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the Office of the Interconnection that is sufficient to enable the Office of the Interconnection to determine the available operating hours of such facilities.

(d) The Market Seller of a resource selected as a pool-scheduled resource shall receive payments or credits for energy, demand reductions or related services, or for Start-up Costs and No-load Costs, from the Office of the Interconnection on behalf of the Market Buyers in accordance with Operating Agreement, Schedule 1, section 3. Alternatively, the Market Seller shall receive, in lieu of Start-up Costs and No-load Costs, its actual costs incurred, if any, up to a cap of the resource's Start-up Costs, if the Office of the Interconnection cancels its selection of the resource as a pool-scheduled resource and so notifies the Market Seller before the resource is synchronized.

(e) Market Participants shall make available their pool-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone.

(f) Economic Load Response Participants offering to reduce demand shall specify: (i) the amount of the offered curtailment, which must equal or exceed 0.1 megawatts, in minimum increments of 0.1 megawatts; (ii) the real-time Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, shut-down costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum number of contiguous hours for which the load reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market and/or the Real-time Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs). Economic Load Response Participants offering to reduce demand shall also indicate the hours that the demand reduction is not available.

1.10.3 Self-scheduled Resources.

Self-scheduled resources shall be governed by the following principles and procedures.

(a) Each Generating Market Buyer shall use all reasonable efforts, consistent with Good Utility Practice, not to self-schedule resources in excess of its Equivalent Load.

(b) The offered prices of resources that are self-scheduled and not dispatchable by the Office of the Interconnection shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.

(c) Market Participants shall make available their self-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone, by submitting an offer as to such resources.

(d) A Market Participant self-scheduling a resource in the Day-ahead Energy Market that does not deliver the energy in the Real-time Energy Market, shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(e) A Market Participant self-scheduling a resource to supply Synchronized Reserve in the Day-ahead Synchronized Reserve Market that does not deliver the scheduled megawatt quantity in the applicable real-time reserve market, shall replace the Synchronized Reserve not delivered and shall pay for such Synchronized Reserve at the applicable Real-time Synchronized Reserve Market Clearing Price. Market Participants shall not self-schedule a resource to provide Secondary Reserve or Non-Synchronized Reserve.

(f) For energy, hydropower units, excluding pumped storage units, may only be self-scheduled.

(g) A resource that has been self-scheduled shall not receive payments or credits for Start-up Costs or No-load Costs.

1.10.4 Capacity Resources.

(a) A Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that is selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection. Such a Generation Capacity Resource that does not deliver energy as scheduled shall be deemed to have experienced a Generator Forced Outage to the extent of such energy not delivered. A Market Participant offering such Generation Capacity Resource in the Day-ahead Energy Market shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Energy from a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that has not been scheduled in the Day-ahead Energy Market may be sold on a bilateral basis by the Market Seller, may be self-scheduled, or may be offered for dispatch during the Operating Day in accordance with the procedures specified in this Schedule. Such a Generation Capacity Resource that has not been scheduled in the Day-ahead Energy Market and that has been sold on a bilateral basis must be made available upon request to the Office of the Interconnection for scheduling and dispatch during the Operating Day if the Office of the Interconnection declares a Maximum Generation Emergency. Any such resource so scheduled and dispatched shall receive the applicable Real-time Price for energy delivered.

1.10.5 External Resources.

(a) External Resources may submit offers to the PJM Interchange Energy Market, in accordance with the day-ahead and real-time scheduling processes specified above. An External Resource selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection, and except as specified below shall be compensated on the same basis as other pool-scheduled resources. External Resources that are not capable of Dynamic Transfer shall, if selected by the Office of the Interconnection on the basis of the Market Seller's Offer Data, be block loaded on an hourly scheduled basis. Market Sellers shall offer External Resources to the PJM Interchange Energy Market on either a resource-specific or an aggregated resource basis. A Market Participant whose pool-scheduled resource does not deliver the energy scheduled in the Day-ahead Energy Market shall replace such energy not delivered as scheduled in the Day-ahead Energy Market with energy from the PJM Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Offers for External Resources from an aggregation of two or more generating units shall so indicate, and shall specify, in accordance with the Offer Data requirements specified by the Office of the Interconnection: (i) energy prices; (ii) hours of energy availability; (iii) a minimum dispatch level; (iv) a maximum dispatch level; and (v) unless such information has previously been made available to the Office of the Interconnection, sufficient information, as specified in the PJM Manuals, to enable the Office of the Interconnection to model the flow into the PJM Region of any energy from the External Resources scheduled in accordance with the Offer Data.

(c) Offers for External Resources on a resource-specific basis shall specify the resource being offered, along with the information specified in the Offer Data as applicable.

1.10.6 External Market Buyers.

(a) Deliveries to an External Market Buyer not subject to Dynamic Transfer by the Office of the Interconnection shall be delivered on a block loaded basis to the bus or buses at the electrical boundaries of the PJM Region, or in such area with respect to an External Market Buyer's load within such area not served by Network Service, at which the energy is delivered to or for the External Market Buyer. External Market Buyers shall be charged (which charge may be positive

or negative) at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing bus or buses.

(b) An External Market Buyer's hourly schedules for energy purchased from the PJM Interchange Energy Market shall conform to the ramping and other applicable requirements of the interconnection agreement between the PJM Region and the Control Area to which, whether as an intermediate or final point of delivery, the purchased energy will initially be delivered.

(c) The Office of the Interconnection shall curtail deliveries to an External Market Buyer if necessary to maintain appropriate reserve levels for a Control Zone as defined in the PJM Manuals, or to avoid shedding load in such Control Zone.

1.10.7 Bilateral Transactions.

Bilateral transactions as to which the parties have notified the Office of the Interconnection by the deadline specified in section 1.10.1A above that they elect not to be included in the Day-ahead Energy Market and that they are not willing to incur Transmission Congestion Charges in the Real-time Energy Market shall be curtailed by the Office of the Interconnection as necessary to reduce or alleviate transmission congestion. Bilateral transactions that were not included in the Day-ahead Energy Market and that are willing to incur congestion charges and bilateral transactions that were accepted in the Day-ahead Energy Market shall continue to be implemented during periods of congestion, except as may be necessary to respond to Emergencies.

1.10.8 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers and PRD Curves properly submitted by PRD Providers; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv) the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated flowgates to the extent provided by Operating Agreement, Schedule 1, section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy

Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) By 1:30 p.m., or as soon as practicable thereafter, of the day before each Operating Day, or such other deadline as may be specified by the Office of the Interconnection in the PJM Manuals, the Office of the Interconnection shall: (i) post the aggregate Day-ahead Energy Market results; (ii) post the Day-ahead Prices; and (iii) inform the Market Sellers, Market Buyers, and Economic Load Response Participants of their scheduled injections, withdrawals, and demand reductions respectively. The foregoing notwithstanding, the deadlines set forth in this subsection shall not apply if the Office of the Interconnection is unable to obtain Market Participant bid/offer data due to extraordinary circumstances. For purposes of this subsection, extraordinary circumstances shall mean a technical malfunction that limits, prohibits or otherwise interferes with the ability of the Office of the Interconnection to obtain Market Participant bid/offer data prior to 11:59 p.m. on the day before the affected Operating Day. Extraordinary circumstances do not include a Market Participant's inability to submit bid/offer data to the Office of the Interconnection. If the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day as a result of such extraordinary circumstances, the Office of the Interconnection shall notify Members as soon as practicable.

(c) Following posting of the information specified in section 1.10.8(b), and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, the Office of the Interconnection shall revise its schedule of generation resources to reflect updated projections of load, conditions affecting electric system operations in the PJM Region, the availability of and constraints on limited energy and other resources, transmission constraints, and other relevant factors.

(d) Market Buyers shall pay PJMSettlement and Market Sellers shall be paid by PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is positive. Market Buyers shall be paid by PJMSettlement and Market Sellers shall pay PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Operating Agreement, Schedule 1, section 3.3A. Notwithstanding the foregoing, if the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day due to extraordinary circumstances as described in subsection (b) above, it will be declared a Market Suspension, and Day-ahead Prices shall be determined pursuant to Operating Agreement, Schedule 1, section 2.6.1. If the Office of the Interconnection declares a Market Suspension, it shall notify Market Participants of the Market Suspension as soon as practicable.

(e) If the Office of the Interconnection discovers a *potential* error in prices and/or cleared quantities in the Day-ahead Energy Market or Day-ahead Ancillary Services Markets, or the Real-time Energy Market or Real-time Ancillary Services Markets after it has posted the results

for these markets on its Web site, the Office of the Interconnection shall notify Market Participants as soon as possible after it is found, but in no event later than 12:00 p.m. of the second Business Day following the Operating Day for the Real-time Energy Market and Real-time Ancillary Services Markets, and no later than 5:00 p.m. of the second Business Day following the initial publication of the results for the Day-ahead Energy Market and Day-ahead Ancillary Services Markets. After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, *along with a description detailing the cause and scope of the error*, by no later than 5:00 p.m. of the fifth Business Day following the Operating Day for the Real-time Energy Market and Real-time Ancillary Services Markets, and no later than 5:00 p.m. of the fifth Business Day following the initial publication of the results in the Day-ahead Energy Market and Day-ahead Ancillary Services Markets. *The provided description will not contain information that is market sensitive or confidential.* Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating Day for the Day-ahead Energy Market, Real-time Energy Market, and Day-ahead Ancillary Services Markets, and Real-time Ancillary Service Markets. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced market results are under publicly noticed review by the FERC.

(f) Consistent with Operating Agreement, section 18.17.1, and notwithstanding anything to the contrary in the Operating Agreement or in the PJM Tariff, to allow the tracking of Market Participants' non-aggregated bids and offers over time as required by FERC Order No. 719, the Office of the Interconnection shall post on its Web site the non-aggregated bid data and Offer Data submitted by Market Participants (for participation in the PJM Interchange Energy Market) approximately four months after the bid or offer was submitted to the Office of the Interconnection.

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, a generation rebidding period shall exist. Typically the rebidding period shall be from the time the Office of the Interconnection posts the results of the Day-ahead Energy Market until 2:15 p.m. on the day before each Operating Day. However, should the clearing of the Day-ahead Energy Market be significantly delayed, the Office of the Interconnection may establish a revised rebidding period. During the rebidding period, Market Participants may submit revisions to generation Offer Data for the next Operating Day. Adjustments to the Day-ahead Energy Market shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 6:30 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 65 minutes prior to the hour in which the adjustment is to take effect, as follows and as specified in section 1.10.9A below:

i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;

ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or

iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or

iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any Start-Up Costs.

(c) An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase in the Day-ahead Energy Market by notifying the Office of the Interconnection of the adjustment in deliveries not later than 65 minutes prior to the hour in which the adjustment is to take effect, but any such adjustment shall not affect the obligation of the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(d) The Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules resulting from the rebidding period by 6:30 p.m. on the day before each Operating Day. The Office of the Interconnection may also commit additional resources after such time as system conditions require. For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this section 1.10, the Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules for the hour.

1.10.9A Updating Offers in Real-time

(a) Each Market Seller may submit Real-time Offers for a resource up to 65 minutes before the applicable clock hour, and such Real-time Offers shall supersede any previous offer for that resource for the clock hour, as further described in the PJM Manuals and subject to the following conditions:

(i) A market-based Real-time Offer shall not exceed the applicable energy offer caps specified in this Schedule. Once a Market Seller's resource is committed for an applicable clock hour, the Market Seller may not increase its Incremental Energy Offer and may only submit a market-based Real-time Offer that is higher than its market-based offer that was in effect at the time of commitment to reflect increases in the resource's cost-based Start-up Costs and cost-based No-load Costs. The Market Seller may elect not to have its market-based offer considered for dispatch and to have only its lowest cost-based offer considered for the remainder of the Operating Day.

(ii) Cost-based Real-time Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2 and the PJM Manuals, as applicable. If a Market Seller submits a market-based Real-time Offer for a particular clock hour in accordance with subsection (c) below, or if updates to a cost-based offer are required by the Market Seller's approved Fuel Cost Policy, the Market Seller shall update its previously submitted cost-based Real-time Offer.

(iii) If a Market Seller's available cost-based offer is not compliant with Operating Agreement, Schedule 2 and the PJM Manuals at the time a Market Seller submits a market-based Real-time Offer for an applicable clock hour during the Operating Day, the Market Seller must submit an updated cost-based Real-time Offer consisting of an Incremental Energy Offer, Start-up Cost, and No-load Cost for that clock hour that is compliant with Operating Agreement, Schedule 2 and the PJM Manuals.

(b) Each Market Seller may submit Real-time Offers for a resource during and through the end of the applicable clock hour to update only the following offer parameters, as further described in the PJM Manuals: (1) Economic Minimum; (2) Economic Maximum; (3) emergency minimum MW; (4) emergency maximum MW; (5) unit availability status; (6) fixed output indicator; (7) Synchronized Reserve maximum MW; and (8) Secondary Reserve maximum MW. Such Real-time Offers shall supersede any previous offer for that resource for the clock hour.

1.10.9B Offer Parameter Flexibility

(a) Market Sellers may, in accordance with sections 1.10.1A and 1.10.9A above, this section 1.10.9B, and the PJM Manuals, update offer parameters at any time up to 65 minutes before the applicable clock hour, including prior to the close of the Day-ahead Energy Market and prior to the close of the rebidding period specified in section 1.10.9, except that Market Sellers may not update their offers for the supply of energy, Secondary Reserve, Synchronized Reserve, Non-Synchronized Reserve, or demand reduction: (1) during the period after the close the Day-ahead Energy Market and prior to the posting of the Day-ahead Energy Market results pursuant to section 1.10.8(b); or (2) during the period after close of the rebidding period and prior to PJM announcing the results of the rebidding period pursuant to section 1.10.9(d).

(b) For generation resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) cost-based Start-up Costs; (2) cost-based No-load Costs; (3) Incremental Energy Offer; (4) Economic Minimum and Economic Maximum; (5) emergency minimum MW and emergency maximum MW; (6) ramp rate; (7) Synchronized Reserve maximum MW; (8) Secondary Reserve maximum MW; and (9) for Real-time Offers only, (i) notification time and (ii) for uncommitted hours only, Minimum Run Time. Notwithstanding the foregoing, Market Sellers of generation resources may vary the notification time for each clock hour for purposes of committing Non-Synchronized Reserve and offline Secondary Reserve in both the Day-ahead and Real-time reserve commitments.

(c) For Economic Load Response Participant resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) shutdown costs, (2) Incremental Energy Offer; (3) Economic Minimum; (4) Economic Maximum; and (5) for Real-time Offers only, (i) notification time and (ii) for uncommitted hours only, minimum down time.

(d) After the announcement of the results of the rebidding period pursuant to section 1.10.9(d), a Market Seller may submit a Real-time Offer where offer parameters may differ from the offer originally submitted in the Day-ahead Energy Market, except that a Market Seller may not submit a Real-time Offer that changes, of the offer parameters listed in section 1.10.1A(d), the MW amounts specified in the Incremental Energy Offer, MW amounts specified in the ramp rate, maximum run time, and availability; provided, however, Market Sellers of dual-fueled resources may submit Real-time Offers for such resources that change the availability of a submitted cost-based offer.

1.12 Dynamic Transfers.

(a) An entity that owns or controls a generating resource in the PJM Region may request that the Transmission Provider electrically remove all or part of the generating resource's output from the PJM Region through a Dynamic Transfer of the output to load outside the PJM Region. Such output shall not be available for economic dispatch by the Office of the Interconnection. A Market Participant otherwise eligible pursuant to section 3.2.3 to submit start-up and no-load values of a generating unit for consideration in calculation of the Energy Make Whole credit shall not be so eligible if all of the output of the generating unit is transferred outside of the PJM Region by a Dynamic Transfer.

(b) An entity that owns or controls a generating resource outside of the PJM Region may request that the Transmission Provider electrically add all or part of the generating resource's output to the PJM Region through a Dynamic Transfer of the output to load inside the PJM Region. A Market Participant otherwise eligible pursuant to section 3.2.3 to submit start-up and no-load values of a generating unit for consideration in calculation of the Energy Make Whole credit shall be so eligible only if all of the output of the generating unit is transferred into the PJM Region by a Dynamic Transfer.

(c) The Transmission Provider may implement Dynamic Transfers pursuant to a request under subsections (a) or (b) above, provided that the requesting entity can demonstrate to the satisfaction of the Transmission Provider that the requesting entity has arranged for the provision of signal processing and communications from the generating unit to the Office of the Interconnection and other participating control areas and remains in compliance with any other procedures and operational requirements established by the Office of the Interconnection regarding Dynamic Transfer as set forth in the PJM Manuals.

(d) An entity requesting a Dynamic Transfer shall be responsible for reserving the amount of transmission service necessary to deliver the range of the Dynamic Transfer and any required ancillary services as applicable. Firm or non-firm transmission service may be used to deliver Dynamic Schedules. Dynamic Schedules are not eligible to provide ancillary services. Only firm transmission service may be used to deliver Pseudo-Ties. Pseudo-Ties are eligible to provide Regulation, Synchronized Reserve and Non-Synchronized Reserve as further described in the PJM Manuals. An entity seeking to utilize a Dynamic Schedule to coordinate operations and beneficially manage congestion in real time with PJM may execute a mutually agreeable interregional congestion management agreement as contemplated in Section 2.6A of this Schedule. An entity seeking to utilize a Pseudo-Tie shall execute a mutually agreeable interregional congestion management agreement as contemplated in Section 2.6A of this Schedule. An entity seeking to utilize a Dynamic Transfer shall execute an agreement prescribing the requirements that must be met before PJM will implement the requested Dynamic Transfer. Dynamic Schedule transactions that occur in real time pursuant to such a congestion management agreement may utilize after-the-fact transmission reservations to account for actual energy transfers.

(e) The Market Participant shall cooperate with PJM to ensure that changes in the Dynamic Transfer value do not adversely impact PJM's management of the PJM Area Control Error in a

manner unacceptable to PJM, and, in the event that PJM, in its sole discretion, determines that the Market Participant's actions in this regard are unacceptable, PJM may terminate the Dynamic Transfer arrangement and may require such additional conditions as it deems appropriate prior to any further Dynamic Transfers.

(f) Market Sellers of generators and other sources otherwise eligible pursuant to Schedule 2 of the PJM Tariff to receive compensation for providing reactive supply and voltage control shall not be so eligible if the generating unit is outside of the PJM Region regardless of whether the generating unit is transferred into the PJM Region by a Dynamic Transfer.

3.2 Market Settlements.

If a dollar-per-MW-hour value is applied in a calculation under this section 3.2 where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW hour value is divided by the number of Real-time Settlement Intervals in the hour.

3.2.1 Spot Market Energy.

(a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with Operating Agreement, Schedule 1, section 2.

(b) Each Market Participant shall be charged for all of its Market Participant Energy Withdrawals scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price to be served in the PJM Interchange Energy Market.

(c) Each Market Participant shall be paid for all of its Market Participant Energy Injections scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price to be delivered to the PJM Interchange Energy Market.

(d) For each Day-ahead Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its Market Participant Energy Withdrawals scheduled times the Day-ahead System Energy Price and the sum of its Market Participant Energy Injections scheduled times the Day-ahead System Energy Price.

(e) For each Real-time Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its real-time Market Participant Energy Withdrawals less its scheduled Market Participant Energy Withdrawals times the Real-time System Energy Price and the sum of its real-time Market Participant Energy Injections less scheduled Market Participant Energy Injections times the Real-time System Energy Price. The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Operating Agreement, Schedule 1, section 3.1A shall be used in determining the real-time Market Participant Energy Withdrawals and Market Participant Energy Injections used to calculate Spot Market Energy charges under this subsection (e).

(f) For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the megawatts of real-time energy injections to be delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region

3.2.2 Regulation.

(a) Each Market Participant that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation Requirement of such Regulation Zone for the hour, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). A Market Participant with an hourly Regulation Obligation shall be charged the pro rata share of the sum of the Regulation market mileage clearing price credits and Regulation market capability clearing price credits for the Real-time Settlement Intervals in an hour.

Regulation Charge = Hourly Regulation Obligation Share * (sum of the Real-time Settlement Interval Regulation credits in an hour)

(b) Each Market Participant supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection shall be credited for each of its resources such that the calculated credit for each increment of Regulation provided by each resource shall be the higher of: (i) the Regulation market-clearing price; or (ii) the sum of the applicable Regulation offers for a resource determined pursuant to section 3.2.2A.1 below, the resource-specific shoulder opportunity costs described in subsection (e) of this section, the resource-specific inter-temporal opportunity costs discussed in subsection (d), and the resource-specific opportunity costs discussed in subsection (e) of this section.

(c) The Office of the Interconnection shall commit resources to provide Regulation every 30 minutes, for the clock intervals of the first 30 minutes of an hour and the second 30 minutes of an hour, up to the Regulation Requirement of such Regulation Zone. The Office of the Interconnection shall select resources in merit order, taking into account the resource's mileage Regulation offer, capability Regulation offer, and estimated resource-specific opportunity cost, all converted into their performance adjusted values as further detailed in the PJM Manuals. The total Regulation market-clearing price in each Regulation Zone shall be determined in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval. The total Regulation market-clearing price shall include: (i) the mileage Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 below shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section Operating Agreement, Schedule 1, section 1.10.1A(e).

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the resource-specific opportunity costs (in dollars) of a resource offering to sell Regulation in each regulating interval, except for hydroelectric resources, shall be equal to the area bounded by (i) Locational Marginal Price at the generation bus for the regulating resource, (ii) the resource's Final Offer, (iii) the resource's tracking ramp-rate limited expected output level if it had been

dispatched for energy in economic merit order, as further described in the PJM Manuals, and (iv) the resource's regulation set point on the energy schedule curve on which the resource is running in the PJM Interchange Energy Market. The area is divided by the resource performance score and further divided by the resource's regulation assigned megawatt to convert to dollars per megawatt.

For hydroelectric resources offering to sell Regulation in a regulating interval, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the full value of the Locational Marginal Price at that generation bus for each megawatt of Regulation capability.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the expected Locational Marginal Price at the generation bus for the hydroelectric resource and the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. Estimated opportunity costs shall be zero for hydroelectric resources for which the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those Real-time Settlement Intervals during which all available units at the hydroelectric resource were operating is higher than the actual Locational Marginal Price at the generator bus for the Real-time Settlement Interval.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating and the expected Locational Marginal Price at the generation bus for the hydroelectric resource. Estimated opportunity costs shall be zero for hydroelectric resources for which the actual Locational Marginal Price at the generator bus for the Real-time Settlement Interval is higher than the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those Real-time Settlement Intervals during which all available units at the hydroelectric resource were operating.

For the purpose of committing resources and setting Regulation market clearing prices, the Office of the Interconnection shall utilize day-ahead Locational Marginal Prices to calculate the average of the Locational Marginal Price values used in the calculation for opportunity costs for hydroelectric resources. For the purposes of settlements, the Office of the Interconnection shall

utilize the real-time Locational Marginal Prices to calculate the average of the Locational Marginal Price used in the calculation for opportunity costs for hydroelectric resources.

Opportunity costs for Economic Load Response Participant resources and regulation-only resources to provide Regulation are zero for the purpose of committing resources, setting Regulation clearing prices, and settlements.

(e) In determining the credit under subsection (b) to a Market Participant selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for (1) each Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Regulation, and (2) the two Real-time Settlement Intervals preceding the regulation commitment and the first two Real-time Settlement Intervals following the regulation commitment in accordance with the PJM Manuals and below.

The unit-specific opportunity cost in dollars, incurred during the Real-time Settlement Interval in which the Regulation obligation is fulfilled, shall be equal to the area bounded by (i) the Locational Marginal Price at the generation bus for the regulating resource, (ii) the resource's Final Offer, (iii) the generation resource's tracking ramp-rate limited expected output level if it had been dispatched in economic merit order, as further described in the PJM Manuals, and (iv) the generation resource's regulation set point, and adjusted for the performance score of the resource. Opportunity costs for Economic Load Response Participant or regulation only resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during each of the preceding two Real-time Settlement Intervals of the regulation commitment shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating Real-time Settlement Interval in order to provide Regulation and the resource's tracking expected ramp rate limited output in each of the preceding two Real-time Settlement Intervals of the regulation commitment times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in each of the preceding two Real-time Settlement Intervals of the regulation commitment and the energy offer, using the Final Offer, at the megawatt level of the Regulation set point for the resource in the initial regulating Real-time Settlement Interval, in the PJM Interchange Energy Market, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during each of the following two Real-time Settlement Intervals of the regulation commitment shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating Real-time Settlement Interval in order to provide Regulation and the resource's tracking expected ramp-rate limited output in each of the following two Real-time Settlement Intervals of the regulation commitment times, and (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in each of the following two Real-time Settlement Intervals of the regulation

commitment and the energy offer, using the Final Offer, at the megawatt level of the Regulation set point for the resource in final regulating hour, in the PJM Interchange Energy Market all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Market Participant in a Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

(g) To determine the Regulation market mileage-clearing price, the Office of the Interconnection shall adjust the submitted mileage offer for each resource in accordance with the historical performance score of that resource, and the amount of historically dispatched Regulation (mileage) calculated by the Office of the Interconnection. The maximum adjusted mileage offer of all cleared resources will set the Regulation market mileage-clearing price.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions, will be credited for Regulation mileage by multiplying the assigned MW(s) by the Regulation market mileage-clearing price, by the ratio between the requested mileage for the Regulation dispatch signal and the historic requested mileage for the Regulation dispatch signal, calculated by the Office of the Interconnection, and by the Regulation resource's performance score calculated in accordance with subsection (j) of this section. For purposes of calculating the credit for Regulation performance, if the hourly movement of the Regulation A dispatch signal equals zero, a value of 0.1 will be used in its place.

(h) The Office of the Interconnection shall divide each Regulation resource's capability offer by the historic performance score for the resource for the purposes of committing resources and setting the market clearing prices.

The Office of the Interconnection shall calculate the Regulation market capability-clearing price for each Regulation Zone by subtracting the Regulation market mileage-clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the Regulation market capability-clearing price for that market Real-time Settlement Interval.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions will be credited for Regulation capability based on the assigned MW and the capability Regulation market-clearing price multiplied by the Regulation resource's performance score calculated in accordance with subsection (j) of this section.

(i) In accordance with the processes described in the PJM Manuals, the Office of the Interconnection shall: (i) calculate inter-temporal opportunity costs for each applicable resource; (ii) include such inter-temporal opportunity costs in each applicable resource's offer to sell

frequency Regulation service; and (iii) account for such inter-temporal opportunity costs in the Regulation market-clearing price.

(j) The Office of the Interconnection shall calculate each Regulation resource's performance score. The performance score shall be a function of the difference in the energy provided versus the energy requested by the Regulation signal while scaling for the number of samples. The error measured shall be the difference of the resources response and the dispatch signal, adjusted by the assigned MW and signal dispatch of the Regulation resource. The performance score is calculated using the following equations:

Performance Score = 1 - 1/n $\sum$ Abs (Error);

Error = Average of Abs (Abs (Response - Regulation Signal) / (0.5*Interval Average Regulation Signal + 0.5*AREG)); and

n = the number of samples in the interval
AREG = assigned regulation megawatt.

The Office of the Interconnection shall calculate a performance score for each Regulation resource for each five-minute period the Regulation resource is assigned to provide Regulation.

The historic performance score will be based on a 100 clock-hour rolling average of the Real-time Settlement Interval performance scores, with consideration of the qualification score, for resources without adequate historical data, as defined in the PJM Manuals.

Regulation resources that have a Real-time Settlement Interval performance score below 25% will be ineligible for Regulation credits for that Real-time Settlement Interval.

Regulation resources that have historical performance scores fall below 40% shall be disqualified from providing Regulation until they are able to re-qualify, as defined in the PJM Manuals.

(k) During a Market Suspension where the suspension is less than or equal to 24 consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Regulation, the resources providing Regulation at the direction of the Office of the Interconnection will be compensated based on a calculated Regulation market-clearing price. Regulation market-clearing prices for each Real-time Settlement Interval associated with such Market Suspension shall be the average of the Regulation market-clearing prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

During a Market Suspension where the suspension is greater than 24 consecutive hours, if the Office of the Interconnection is assigning Regulation, resources providing Regulation at the direction of the Office of the Interconnection will be compensated based on a calculated Regulation clearing price. The Regulation clearing price for each Real-time Settlement Interval will be determined by calculating a Regulation clearing cost for the online resources providing Regulation during the Market Suspension. The resource's Regulation

clearing cost is determined by the summation of their adjusted Regulation offer and adjusted opportunity cost. The opportunity cost will be based on the resource's cost-based offer and will be determined as
follows:

> For online resources providing Regulation on a cost-based offer at the time of the Market Suspension, that cost-based offer will be used.
>
> For online resources providing Regulation on a price-based offer at the time of the Market Suspension, the Office of the Interconnection shall use the cheapest available cost-based offer based on the dispatch cost formula as defined in Operating Agreement, Schedule 1, section 6.4.1(g) using the available cost-based offers in the Office of the Interconnection system at the time of the Market Suspension.

The highest cost resource, based on this Regulation clearing cost, will set the Regulation market-clearing price for each hour of the Market Suspension.

During a Market Suspension, if the Office of the Interconnection is not assigning Regulation resources, then the Regulation market-clearing price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period and no resource-specific opportunity cost will be calculated.

During a Market Suspension, the following Regulation components for all Real-time Settlement Intervals in the Market Suspension period will be determined as follows:

(i) If the regulation performance score cannot be calculated during a Market Suspension, the historic performance score will be used for the Market Suspension period.

(ii) If the regulation mileage cannot be calculated during a Market Suspension, the mileage will be set to one (1) for the Market Suspension period.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) For each Regulation market clearing interval, the Office of the Interconnection shall conduct a Regulation three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the Regulation three-pivotal supplier test shall be capped in the interval in which they failed the test at their cost based offers as determined pursuant to Operating Agreement, Schedule 1, section 1.10.1A(e). A Regulation supplier fails the three-pivotal supplier test in any Regulation market clearing interval in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

(b) For the purposes of conducting the three-pivotal supplier test pursuant to this section, the following applies:

(i) The Regulation three-pivotal supplier test will include in the definition of available supply all offer megawatts from resources capable of satisfying the Regulation Requirement of the PJM Region multiplied by the historic performance score of the resource for which the capability cost-based offer plus the mileage cost-based offer plus any eligible opportunity costs is no greater than 150% of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The Regulation three-pivotal supplier test will apply on a Regulation supplier basis (i.e. not a resource by resource basis) and only the Regulation suppliers that fail the three-pivotal supplier test will have their Regulation offers capped. A Regulation supplier for the purposes of this section includes corporate affiliates. Regulation from resources controlled by a Regulation supplier or its affiliates, whether by contract with unaffiliated third parties or otherwise, will be included as Regulation of that Regulation supplier. Regulation provided by resources owned by a Regulation supplier but controlled by an unaffiliated third party, whether by contract or otherwise, will be included as Regulation of that third party.

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the Regulation Requirement for the Regulation clearing interval to determine the residual supply index. Where the residual supply index for Regulation three pivotal suppliers is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Energy Uplift.

(a) A Market Seller's pool-scheduled resources shall be credited as specified below for Energy Make Whole credits.

(b) Day-ahead Energy Make Whole credits shall be calculated in the following manner for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for Start-up Costs and No-load Costs and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. PJM shall also (i) determine whether any resources were scheduled in the Day-ahead Energy Market to provide Black Start Service, Reactive Services or transfer interface control during the Operating Day because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day in

order to minimize the total cost of Operating Reserves associated with the provision of such services and reflect the most accurate possible expectation of real-time operating conditions in the day-ahead model, which resources would not have otherwise been committed in the day-ahead security-constrained dispatch and (ii) report on the day following the Operating Day the megawatt quantities scheduled in the Day-ahead Energy Market for the above-enumerated purposes for the entire RTO.

Except as provided in section 3.2.3(n) below, if the total offered price for Start-up Costs (shutdown costs for Economic Load Response Participant resources) and No-load Costs and energy summed over all Day-ahead Settlement Intervals exceeds the total value summed over all Day-ahead Settlement Intervals, the difference shall be credited to the Market Seller as day-ahead Energy Make Whole credits.

However, for the Day-ahead Settlement Intervals in which the resource is scheduled to provide energy in the Operating Day and the resource actually provides energy in at least one Real-time Settlement Interval in an hour that corresponds to such scheduled Day-ahead Settlement Intervals, a resource's day-ahead Energy Make Whole credit shall be reduced by the greater of zero or the difference of the resource's day-ahead Energy Make Whole target and the balancing Energy Make Whole target, as determined below.

A resource's day-ahead Energy Make Whole target shall be determined in accordance with the following equation:

(A + B) - C

Where:

A = Start-up Costs

B = the sum of day-ahead No-load Costs and energy over the applicable Real-time Settlement Intervals that correspond with Day-ahead Settlement Intervals in which the resource is scheduled. The day-ahead No-load Costs and energy are divided by twelve to determine the cost for each Real-time Settlement Interval.

C = the sum of the day-ahead revenues calculated for each Real-time Settlement Interval that corresponds with a Day-ahead Settlement Interval in which the resource is scheduled, where the day-ahead revenue for each such Real-time Settlement Interval equals the product of the megawatt amount of energy scheduled in the Day-ahead Energy Market and the Day-ahead Price at the applicable pricing point for the resource divided by twelve.

A resource's balancing Energy Make Whole target shall be determined in accordance with the following equation:

D – (E + F)

Where:

D = the Real-time Cost, as defined in subsection 3.2.3(e-2)(ii) of this section, summed over all Real-time Settlement Intervals that correspond to the Day-ahead Settlement Intervals in which the resource was scheduled;

E = [(the megawatt amount of energy provided in the Real-time Energy Market minus the megawatt amount of energy scheduled in the Day-ahead Energy Market) multiplied by the Real-time Price at the applicable pricing point for the resource] plus the sum of the day-ahead revenues as determined in part C of the above formula for determining the Day-ahead Energy Make Whole target, summed over the Real-time Settlement Intervals that correspond to the Day-ahead Settlement Intervals in which the resource was scheduled; and

F = the sum of all Other Market Revenues, as defined in subsection 3.2.3(e-2)(ii) of this section, over the Real-time Settlement Intervals that correspond to the Day-ahead Settlement Intervals in which the resource was scheduled.

(c) The sum of the foregoing credits calculated in accordance with section 3.2.3(b) plus any unallocated charges from section 3.2.3(h) and Operating Agreement, Schedule 1, section 5.1.7, and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of Energy Make Whole credits in the Day-ahead Energy Market.

(d) The cost of Energy Make Whole credits in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load ((a) net of Behind The Meter Generation expected to be operating, but not to be less than zero; and (b) excluding Direct Charging Energy), accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day and accepted Up-to Congestion Transactions in the Day-ahead Energy Market in megawatt-hours for the Operating Day at the sink of the transaction; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside such area pursuant to Operating Agreement, Schedule 1, section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Energy Make Whole credits in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Tariff, Schedule 6A. The cost of Energy Make Whole credits in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load ((a) net of operating Behind The Meter Generation; and (b)

excluding Direct Charging Energy) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

(e) (i) Pool-scheduled generation resources that operate for at least one Real-time Settlement Interval within the pool-scheduled commitment period are eligible for balancing Energy Make Whole credits as further detailed in this section and in the PJM Manuals. Balancing Energy Make Whole credits eligibility for Economic Load Response Participant resources is detailed in Operating Agreement, Schedule 1, section 3.2.3(o-1) of this section. A pool-scheduled generation resource's eligibility for balancing Energy Make Whole credits begins at the first Real-time Settlement Interval of a pool-scheduled commitment. The generation resource remains eligible for balancing Energy Make Whole credits until the later of:

1) the Real-time Settlement Interval corresponding to the end of its Day-ahead Energy Market commitment or the end of its Minimum Run Time, as applicable

or

2) the Real-time Settlement Interval when the resource is no longer running under the direction of the Office of the Interconnection.

Additionally, generation resource types with no soak process in the Start-up Cost are eligible for balancing Energy Make Whole credits for a pre-commitment period prior to the first Real-time Settlement Interval of the pool-scheduled commitment to account for ramping costs. The pre-commitment period begins with the Real-time Settlement Interval when a generation resource comes online but may not begin earlier than four Real-time Settlement Intervals (20 minutes) prior to the first Real-time Settlement Interval of the pool-scheduled commitment. However, a generation resource is only eligible for this pre-commitment period if the price and megawatt quantities submitted as part of its Incremental Energy Offer, using the lesser of the Final Offer or Committed Offer as determined using the Actual MWh during the pre-commitment period, are less than or equal to the price and megawatt quantities of its Incremental Energy Offer using the Committed Offer for the first hour of the commitment. Generation resource types with a soak process in the Start-up Cost are not eligible during the pre-commitment period.

Pool-scheduled generation resources that are released by the Office of Interconnection and ramping offline are additionally eligible for balancing Energy Make Whole credits for post-commitment Real-time Settlement Intervals until the Real-time Settlement Interval that the generation resource goes offline; however, eligibility shall not extend beyond the Real-time Settlement Interval in which the resource is no longer running under the direction of the Office of Interconnection plus the number of Real-time Settlement Intervals corresponding to the allowable ramp down period for the resource

type, as specified in the PJM Manuals. However, a generation resource is only eligible for this post-commitment period if the price and megawatt quantities submitted as part of its Incremental Energy Offer, using the lesser of the Final Offer or Committed Offer as determined using the Actual MWh during the post-commitment period, is less than or equal to the price and megawatt quantities of its Incremental Energy Offer using the Committed Offer for the last hour of the commitment.

(ii) The balancing Energy Make Whole credit calculation will be conducted on a segmented basis. For each Operating Day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two Segments for each resource.

The first Segment will be defined as the greater of the applicable day-ahead commitment and Minimum Run Time specified at the time of commitment (minimum down time specified at the time of commitment for Economic Load Response Participant resources). Further, if a generation resource is no longer running under the direction of the Office of the Interconnection within 30 minutes after the end of the first Segment, the first Segment will also include the remainder of the Real-time Settlement Intervals in which the resource operated at the direction of the Office of the Interconnection.

The second Segment will be defined as any block of contiguous Real-time Settlement Intervals the resource runs under the direction of the Office of the Interconnection in excess of the first Segment.

Notwithstanding the foregoing, each Segment shall be limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

(iii) If a Market Seller submits an offer parameter that exceeds the applicable approved parameter limit on a parameter-limited schedule for a generation resource and such parameter affects the MW dispatch level of the resource in a given settlement interval, the resource will remain eligible for the energy uplift credit calculation but shall not recover any costs incurred during the affected settlement intervals. If such parameter impacts the commitment decision in a manner that could lead to the Office of the Interconnection committing the generation resource to produce energy for longer than it otherwise would have, the resource will not be eligible for the energy uplift credit calculation for the commitment duration. A generation resource that is the subject to an offer parameter on a parameter-limited schedule that exceeds its approved parameter limits may still be eligible for energy uplift credits if the Market Seller of such resource can justify to the Office of the Interconnection that the need to operate outside of such unit-specific parameters was the result of an actual constraint.

A Market Seller shall provide to the Market Monitoring Unit and the Office of the Interconnection its request to receive energy uplift credits for such operation, along with documentation explaining in detail the reasons for operating its resource outside of its unit-specific parameters, within thirty calendar days following the issuance of the billing statement for the Operating Day. The Market Seller shall also respond to additional

requests for information from the Market Monitoring Unit and the Office of the Interconnection. The Market Monitoring Unit shall evaluate such request for compensation and provide its determination of whether there was an exercise of market power to the Office of the Interconnection by no later than twenty-five calendar days after receiving the Market Seller's request for compensation. The Office of the Interconnection shall make its determination whether the Market Seller justified that it is entitled to receive energy uplift credits for such operation of its resource for the day(s) in question, by no later than thirty calendar days after receiving the Market Seller's request for compensation.

(iv) Nuclear generation resources shall not be eligible for energy uplift payments unless: 1) the Office of the Interconnection directs such resources to reduce output, in which case, such units shall be compensated in accordance with Tariff, Attachment K-Appendix, section 3.2.3(f) and the parallel provision of Operating Agreement, Schedule 1, section 3.2.3(f); or 2) the resource submits a request for a risk premium to the Market Monitoring Unit under the procedures specified in Tariff, Attachment M – Appendix, section II.B. A nuclear generation resource (i) must submit a risk premium consistent with its agreement under such process, or, (ii) if it has not agreed with the Market Monitoring Unit on an appropriate risk premium, may submit its own determination of an appropriate risk premium to the Office of the Interconnection, subject to acceptance by the Office of the Interconnection, with or without prior approval from the Commission.

(e-1) The Tracking Ramp Limited Desired (TRLD) metric is used in the calculation of balancing Energy Make Whole credits and generator deviation charges as a representation of the level at which the resource would be desired if operating as requested by the Office of the Interconnection. There are two Tracking Ramp Limited Desired metrics, one measured in MW (power) and the other measured in MWh (energy), each of which are calculated as described below and as further detailed in the PJM Manuals. The Tracking Ramp Limited Desired MWh (energy) calculated for each Real-time Settlement Interval shall be used in the calculation of balancing Energy Make Whole credits and generator deviations. The Tracking Ramp Limited Desired MWh (energy) value represents the expected energy produced between the start of the Real-time Settlement Interval and the end of the Real-time Settlement Interval.

For purposes of this Operating Agreement, Schedule 1, section 3.2.3, the minimum operating limit used herein shall be the Economic Minimum unless the Office of the Interconnection has declared Minimum Generation Emergency conditions, in which case it shall be the emergency minimum. Also, the maximum operating limit shall be the Economic Maximum unless the Office of the Interconnection has declared Maximum Emergency conditions, in which case it shall be the emergency maximum.

(i) Tracking Ramp Limited Desired MW (power) is an adjusted metric that accounts for the impact of Regulation and reserve assignments or manual dispatch instructions.

The Tracking Ramp Limited Desired MW (power) calculation starts at time t_0, which is when a generation resource is first expected by the Office of Interconnection to be online

or when a generation resource is dispatchable, while honoring soak time differences, as further detailed in the PJM Manuals.

The Tracking Ramp Limited Desired MW (power) metric will be calculated as follows. For the Real-time Settlement Interval equal to $t_{0,}$

If a generation resource does not have a soak process and is directed to come online as soon as possible,

TRLD MW (power) = 0

Otherwise,
TRLD MW (power)
= Max [Min (LMP Desired MW, Dispatch MW), Tracking Desired Economic Minimum]

Where:
LMP Desired MW = the generation resource's expected output level based on its Final Offer at the Real-time Locational Marginal Price from the dispatch run at the applicable pricing point
Dispatch MW = energy dispatch signal MW from the dispatch run
Tracking Desired Economic Minimum = the generation resource's minimum operating limit, as specified in Operating Agreement, Schedule 1, section 3.2.3(e-1), unless any of the following conditions occur,

- If a resource is requested to increase output due to a transmission constraint or other reliability issue, Tracking Desired Economic Minimum = the lower limit from the manual dispatch instruction as directed by the Office of the Interconnection.

- If the resource's minimum operating limit increases by more than 5% of the resource's minimum operating limit at the time of commitment, the minimum operating limit at the time of commitment will be used.

For each Real-time Settlement Interval after the resource's initial start time, t_0, Tracking Ramp Limited Desired MW (power) shall be calculated as follows:

$$\text{TRLD MW}_t \text{ (power)} = \text{TRLD MW}_{t-1} \pm \text{Ramp}_t$$

Where:
t = Start time of Real-time Settlement Interval for which the metric is being calculated
Ramp = Increase or decrease in MW calculated using the Real-time Locational Marginal Price from the dispatch run at the applicable pricing point, the resource's Final Offer, and the ramp rate parameters. The increase or decrease in MW is restricted by the most limiting of the following parameters among the

ramp rate, the Tracking Desired Economic Minimum, and the Tracking Desired Economic Maximum, where:

Tracking Desired Economic Minimum = defined above in the calculation for TRLD MW_{t0}
Tracking Desired Economic Maximum = the generation resource's maximum operating limit unless any one of the following conditions occur:

- If a resource is requested to decrease output due to a transmission constraint or other reliability issue, Tracking Desired Economic Maximum = the upper limit from the manual dispatch instruction as directed by the Office of the Interconnection.

- If a resource's maximum operating limit decreases by more than 5% of the resource's maximum operating limit at the time of commitment, the maximum operating limit at the time of commitment will be used.

The Tracking Ramp Limited Desired MW (power) value will be further adjusted, as specified below, if the resource has a regulation or reserve assignment and is unable to provide such assignment while generating the initial Tracking Ramp Limited Desired MW due to the resource's applicable operating parameters.

- If the Tracking Ramp Limited Desired MW is above the highest MW point at which the resource can provide the Regulation or reserve assignments, the Tracking Ramp Limited Desired MW will be lowered to the highest point at which it can provide the assignment(s) based on the resource's applicable operating parameters.

- If the Tracking Ramp Limited Desired MW is below the lowest MW point at which the resource can provide the Regulation assignment, the Tracking Ramp Limited Desired MW will be increased to the lowest point at which it can provide the regulation assignment based on the resource's applicable operating parameters.

This adjusted Tracking Ramp Limited Desired MW value is used in calculating the Tracking Ramp Limited Desired MW (power) for subsequent intervals.

(ii) An unadjusted Tracking Ramp Limited Desired MW (power) that excludes the impact of Regulation and reserve assignments or manual dispatch instructions is also calculated for conversion to an unadjusted Tracking Ramp Limited Desired MWh (energy) metric which is used in the Other Market Revenue and Opportunity Cost Owed calculations described in subsection 3.2.3(e-2)(i). The unadjusted Tracking Ramp Limited Desired MW (power) metric will be calculated as follows.

For the Real-time Settlement Interval equal to $t_{0,}$ the unadjusted Tracking Ramp Limited Desired MW (power) equals the Tracking Ramp Limited Desired MW $(power)_{t0}$ as

calculated in subsection (i) directly above excluding the impact of regulation and reserve assignments or manual dispatch instructions.

For each Real-time Settlement Interval after the start time, t_0, the unadjusted Tracking Ramp Limited Desired MW (power) shall be calculated as follows:

unadjusted TRLD MW_t (power) = unadjusted TRLD $MW_{t-1} \pm Ramp_t$

Where:

t = Start time of Real-time Settlement Interval for which the metric is being calculated

Ramp = Increase or decrease in MW calculated using the Real-time Locational Marginal Price from the dispatch run at the applicable pricing point, the resource's Final Offer, and the ramp rate parameters. The increase or decrease in MW is restricted by the most limiting parameter among the ramp rate, the unadjusted economic minimum, and the unadjusted economic maximum, where:

unadjusted economic minimum = minimum operating limit for the Real-time Settlement Interval unless such minimum operating limit increased by more than 5% of the resource's minimum operating limit at the time of commitment, in which case the minimum operating limit at the time of commitment shall be used.

unadjusted economic maximum = maximum operating limit for the Real-time Settlement Interval unless such maximum operating limit decreased by more than 5% of the resource's maximum operating limit at the time of commitment, in which case the maximum operating limit at the time of commitment shall be used.

(iii) The Tracking Ramp Limited Desired MW (power) calculations in Operating Agreement, Schedule 1, section 3.2.3(e-1)(i) and (ii) above will continue until the resource goes offline; however, if a generation resource trips or is taken offline at the request of the Market Seller prior to the later of the end of the Day-ahead Energy Market commitment or the end of the Minimum Run Time, the values will continue to be calculated per the calculations defined above until the later of the end of the Day-ahead Energy Market commitment or the end of the Minimum Run Time.

Further, once the Office of the Interconnection releases a generation resource to go offline, provided that the resource actually goes offline following such direction, the Tracking Ramp Limited Desired MW shall be calculated using only the ramp down parameters such that the Tracking Ramp Limited Desired MW is incrementally ramped down to its minimum output, irrespective of the real-time LMP. During this time period, the unadjusted Tracking Ramp Limited Desired MW (power) will equal the Tracking Ramp Limited Desired MW (power) unless the resource has been manually dispatched

offline, in which case the unadjusted Tracking Ramp Limited Desired MW (power) will continue as specified above in Operating Agreement, Schedule 1, section 3.2.3(e-1)(ii) until the manual dispatch instruction ends.

TRLD MW_t (power) =

Max (TRLD MW_{t-1} – Down $Ramp_t$, Tracking Desired Economic $Minimum_t$)

Where Down Ramp = Decrease in MW utilizing the resource's down ramp rate parameter.

(iv) The Tracking Ramp Limited Desired MW (power) and unadjusted Tracking Ramp Limited Desired MW (power) metrics will be converted to the Tracking Ramp Limited Desired MWh (energy) metrics that shall be used in the calculation of balancing Energy Make Whole credits and generator deviations. For all Real-time Settlement Intervals prior to the start time of the Tracking Ramp Limited Desired MW (power) calculations, t_0 as defined above, both the Tracking Ramp Limited Desired MWh (energy) and the unadjusted Tracking Ramp Limited Desired MWh (energy) shall be equal to the resource's Actual MWh for that Real-time Settlement Interval. For purposes of this section, Actual MWh equals the Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Tariff, Attachment K-Appendix, section 3.1A and parallel provisions in Operating Agreement, Schedule 1, section 3.1A.

For each Real-time Settlement Interval after the Office of the Interconnection releases a generation resource to go offline and the resource's Actual MWh is below the minimum operating limit, the Tracking Ramp Limited Desired MWh (energy) and the unadjusted Tracking Ramp Limited Desired MWh (energy) shall be equal to Actual MWh of the resource.

For all other Real-time Settlement Intervals, the Tracking Ramp Limited Desired MWh (energy) shall equal the expected energy produced between the start of the Real-time Settlement Interval and the end of the Real-time Settlement Interval based on the Tracking Ramp Limited Desired MW (power) at the start and at the end of the Real-time Settlement Interval and the resource's ramping capability, as further described in the PJM Manuals. The unadjusted Tracking Ramp Limited Desired MWh (energy) shall equal the expected energy produced between the start of the Real-time Settlement Interval and the end of the Real-Time Settlement Interval based on the unadjusted Tracking Ramp Limited Desired MW (power) at the start and at the end of the Real-time Settlement Interval and the resource's ramping capability, as further described in the PJM Manuals.

(v) The Tracking Ramp Limited Desired MW (power) and MWh (energy) values described above in subsections Operating Agreement, Schedule 1, section 3.2.3(e-1)(i) and (ii), as may be qualified by (iii), and (iv) of this section may be further adjusted as described in the PJM Manuals to account for instances where the Office of the Interconnection is unable to dispatch the system using the real-time security constrained economic dispatch system and/or where the real-time security-constrained economic

dispatch application is providing dispatch signals inconsistent with the resource's offer data, or other abnormal dispatch scenarios.

(e-2) For generating resources, balancing Energy Make Whole credits received pursuant to this section shall be equal to the lesser of the Tracking Balancing Energy Make Whole Credit, as calculated in Step 1 below in Operating Agreement, Schedule 1, section 3.2.3(e-2)(i), and the Actual Balancing Energy Make Whole Credit, as calculated in Step 2 below in Operating Agreement, Schedule 1, section 3.2.3(e-2)(ii), for each Segment in the Operating Day, except as provided in this Operating Agreement, Schedule 1, section 3.2.3(m). Balancing Energy Make Whole credits for Economic Load Response Participant resources shall be equal to the credits as determined in Operating Agreement, Schedule 1, section 3.3.A.

(i) Step 1: Calculate Tracking Balancing Energy Make Whole credit for the Segment using Tracking Ramp Limited Desired MWh.

Tracking Balancing Energy Make Whole Credit = A – B

Where
$A = -1 \times \sum_t$ Tracking Balancing Net Revenue$_t$
Where t = the eligible Real-time Settlement Intervals in the applicable Segment

B = Day-ahead Energy Make Whole Credit as determined pursuant to section 3.2.3(b) if the Segment is the first Segment. For all other Segments, B = 0.

Tracking Balancing Energy Make Whole Credit shall not be less than zero.

The Tracking Balancing Net Revenue for each Real-time Settlement Interval in the Segment shall be calculated in accordance with the following equation:

Tracking Balancing Net Revenue$_t$ = (DA Revenue$_t$ + Balancing Revenue$_t$ + Other Market Revenue$_t$ + Opportunity Cost Owed$_t$) - Real-time Cost$_t$

Where
t = the Real-time Settlement Interval

DA Revenue = Day-ahead Energy Market Revenue for the Real-time Settlement Interval in accordance with the following equation:
Day-ahead Scheduled MWh × Day-ahead LMP

Balancing Revenue = Balancing Energy Market Revenue in accordance with the following equation:
(Tracking Ramp Limited Desired MWh ─ Day-ahead Scheduled MWh) × Real-time LMP ─ Company Responsible Negative Revenues
Where: Company Responsible Negative Revenues = any negative balancing revenues in excess of the Day-ahead Energy Market revenue

that results from the Market Participant's actions reducing the resource's flexibility as further specified in the PJM Manuals. This is calculated as:

MW unavailable due to limited flexibility × Min (Day-ahead LMP ─ Real-Time LMP, 0)

Other Market Revenue = SR + SecR + NSR + Reactive + LOC + Reg

Where
SR = any potential credits for providing Synchronized Reserve determined in accordance with the credit calculations in Operating Agreement, Schedule 1, section 3.2.3A(b) less the resource's Synchronized Reserve offer price, in dollars, included in the resource's Synchronized Reserve potential lost opportunity cost credit in Operating Agreement, Schedule 1, section 3.2.3A(f)(iv).

SecR = any potential credits for providing Secondary Reserve determined in accordance with the credit calculations in Operating Agreement, Schedule 1, section 3.2.3A.01(b)

NSR = any amounts credited for providing Non-Synchronized Reserve as specified in Operating Agreement, Schedule 1, section 3.2.3A.001(b)

Reactive = any potential credits for providing Reactive Services determined in accordance with the credit calculations in Operating Agreement, Schedule 1, section 3.2.3B

LOC = any potential lost opportunity cost credits determined in Operating Agreement, Schedule 1, sections 3.2.3(f) – 3.2.3(f-6).

Reg = any potential Regulation opportunity cost amounts determined in accordance with the calculations for use in settlements in Operating Agreement, Schedule 1, section 3.2.2.

Opportunity Cost Owed = the sum of the potential opportunity costs owed for Synchronized Reserve, Non-Synchronized Reserve, and Secondary Reserve as determined in accordance with Sections 3.2.3A(f)(iv), 3.2.3A.001(d)(iii) and 3.2.3A.01(f)(iv), respectively.

For the purposes of the above Other Market Revenue and Opportunity Cost Owed calculations, the potential credits and costs are determined using the calculations referenced above and the assumption that the resource was increased or decreased from the unadjusted Tracking Ramp Limited Desired MWh in order to provide the assignment or PJM directed MW as further described in the PJM Manuals.

Real-time Cost = (Incremental Offer + No Load Cost + Start-Up Cost)

Where

Incremental Offer = Real-time incremental energy offer, in dollars, based on the area under the incremental energy offer curve calculated using the Tracking Ramp Limited Desired MWh

No Load = Real-time No-load Cost

Start-Up = Real-time Start-Up Cost, if it is a Real-time Settlement Interval in the first Segment

The offer used for calculating Real-time Cost shall be the lesser of the Committed Offer or Final Offer based on the offer with the lowest total cost for the hour.

The above Balancing Revenue and Real-time Cost calculations shall be further modified for Real-time Settlement Intervals preceding the start of the commitment for generation resource types with no soak process in the Start-up Cost by capping the Tracking Ramp Limited Desired MWh (energy) at the minimum operating limit for such interval.

The above Balancing Revenue and Real-time Cost calculations shall be reduced by the costs incurred and revenues received in the applicable Real-time Settlement Intervals for generation resource types with a soak process in the Start-up Cost when the Tracking Ramp Limited Desired MWh (energy) indicate the unit is not dispatchable by the Office of the Interconnection during a Real-time Settlement Interval when it was scheduled to be dispatchable since those costs and revenues may already be included in the Start-Up Cost as further defined in the PJM Manuals.

During Real-time Settlement Intervals where a Flexible Resource is self-scheduled and was committed by the Office of the Interconnection in the Day-ahead Energy Market for the same Real-time Settlement Interval, the above calculation will use the Tracking Balancing Net Revenues that the resource would have received if it had followed PJM real-time commitment instructions and remained offline; provided that if the unit is taken over by company to run as self-scheduled prior to the Minimum Run Time of a pool scheduled commitment elapsing, this shall only apply to those Real-time Settlement Intervals beyond the Minimum Run Time.

(ii) Step 2: Calculate balancing Energy Make Whole credits for the Segment using Actual MWh.

Actual Balancing Energy Make Whole Credit = A – B

Where

$A = -1 \times \sum_t$ Actual Balancing Net Revenue$_t$

Where t = the eligible Real-time Settlement Intervals in the applicable Segment

B = Day-ahead Energy Make Whole Credit as determined pursuant to section 3.2.3(b) if the Segment is the first Segment; else, 0

Actual Balancing Energy Make Whole Credit shall not be less than zero.

The Actual Balancing Net Revenue for each Real-time Settlement Interval in the Segment shall be calculated in accordance with the following equation. For purposes of this section, the Actual MWh equals the Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Operating Agreement, Schedule 1, section 3.1A.

Actual Balancing Net Revenue$_t$ = (DA Revenue$_t$ + Balancing Revenue$_t$ + Other Market Revenue$_t$) - Real-time Cost$_t$

Where
t = the Real-time Settlement Interval

DA Revenue = Day-ahead Energy Market Revenue for the Real-time Settlement Interval in accordance with the following equation:

Day-ahead Scheduled MWh × Day-ahead LMP

Balancing Revenue = Balancing Energy Market Revenue for the Real-time Settlement Interval in accordance with the following equation:

(Actual MWh – Day-ahead Scheduled MWh) × Real-time LMP ─ Company Responsible Negative Revenues

Where: Company Responsible Negative Revenues = any negative balancing revenues in excess of the DA revenue based on the Market Participant's actions reducing flexibility as further specified in the PJM Manuals. This is calculated as:

MW unavailable due to limited flexibility × Min (Day-ahead LMP ─ Real-Time LMP, 0)

Other Market Revenue = SR + SecR + NSR + Reactive + LOC + Reg

Where:
SR = any amounts credited for providing Synchronized Reserve equal to the credits as determined in Operating Agreement, Schedule 1, section 3.2.3A(b) less the resource's Synchronized Reserve offer price, in dollars, included in the resource's Synchronized Reserve lost opportunity cost credit calculation in Operating Agreement, Schedule 1, section 3.2.3A(f)(iv)

SecR = any amounts credited for providing Secondary Reserve as determined in Operating Agreement, Schedule 1, section 3.2.3A.01 (b)

NSR = any amounts credited for providing Non-Synchronized Reserve as determined in Operating Agreement, Schedule 1, section 3.2.3A.001(b)

Reactive = any amounts credited for providing Reactive Services as determined in Operating Agreement, Schedule 1, section 3.2.3B

LOC = any lost opportunity costs credits as determined in Operating Agreement, Schedule 1, sections 3.2.3(f) – 3.2.3(f-6); and

Reg =any Regulation opportunity cost amounts as calculated for purposes of settlements in Operating Agreement, Schedule 1, section 3.2.2

Real-time Cost = (Incremental Offer + No Load + Start-Up)

Incremental Offer = Real-time incremental energy offer, in dollars, based on the area under the incremental energy offer curve calculated using the Actual MWh

No Load = Real-time No-load Cost

Start-Up = Real-time Start-Up Cost, if it is within the first Segment

The offer used for calculating Real-time Cost shall be the Final Offer for the hour.

The above Balancing Revenue and Real-time Cost calculations shall be reduced by the costs incurred and revenues received in the applicable Real-time Settlement Intervals for generation resource types with a soak process in the Start-up Cost when the Actual MWh indicate the resource is not dispatchable by the Office of the Interconnection during a Real-time Settlement Interval when it was scheduled to be dispatchable by the Office of the Interconnection since those costs and revenues may already be included in the Start-Up Cost as further defined in the PJM Manuals.

The above Balancing Revenue and Real-time Cost calculation shall be further modified for Real-time Settlement Intervals preceding the start of the commitment for generation resource types with no soak process in the Start-up Cost, by capping the Actual MWh at the minimum operating limit for each such interval.

(iii) In the event of a real-time Market Suspension, if the Office of the Interconnection and the Market Monitoring Unit determine that the generation resource was not following dispatch instructions, the generation resource shall be ineligible for balancing Energy Make Whole credits. If the generation resource is eligible during a real-time Market Suspension, the balancing Energy Market Whole credit shall be equal to the actual balancing Energy Make Whole credit, as determined in subsection 3.2.3(e-2)(ii) of this section.

(iv) A price-sensitive pool-scheduled import transaction shall receive balancing Energy Make Whole credits equal to the positive difference between a transaction's offer, and the total value of the transaction's energy in the Day-ahead Energy Market plus any credit or charge for quantity deviations from the Day-ahead Energy Market at the real-time LMP(s) applicable to the sink of the transaction summed over all Real-time Settlement Intervals in the Operating Day.

(f) A Market Seller of a unit not defined in subsection (f-1), (f-2), or (f-4) hereof (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3(c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the LOC Deviation times (B) the Locational Marginal Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C. A Market Seller of a unit defined in subsection (f-1), (f-2), (f-3), (f-4), or (f-5) that is reduced using a generator output constraint to honor a stability limitation is not eligible for credits under this section 3.2.3(f) for the MWh reduction associated with honoring the stability limit. If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.11.6, where the suspension is greater than twenty-four (24) consecutive hours, resources will not be compensated for lost opportunity costs.

(f-1) With the exception of Market Sellers of Flexible Resources that submit a Real-time Offer greater than their resource's Committed Offer in the Day-ahead Energy Market, a Market Seller of a Flexible Resource shall be compensated for lost opportunity cost, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described in section 3.2.3(f).

(ii) If the unit is scheduled to produce energy in the Day-ahead Energy Market for a Day-ahead Settlement Interval, but the unit is not called on by the Office of the Interconnection and does not operate in the corresponding Real-time Settlement Interval(s), then the Market Seller shall be credited in an amount equal to the higher of:

1) the product of (A) the amount of megawatts committed in the Day-ahead Energy Market for the generating unit, and (B) the

Real-time Price at the generation bus for the generating unit, minus the sum of (C) the Total Lost Opportunity Cost Offer plus No-load Costs, plus (D) the Start-up Cost, divided by the Real-time Settlement Intervals committed for each set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market. This equation is represented as (A*B) - (C+D). The startup cost, (D), shall be excluded from this calculation if the unit operates in real time following the Office of the Interconnection's direction during any portion of the set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market, or

2) the Real-time Price at the unit's bus minus the Day-ahead Price at the unit's bus, multiplied by the number of megawatts committed in the Day-ahead Energy Market for the generating unit.

(f-2) A Market Seller of a hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3(c), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-4) A Market Seller of a wind or solar generating unit, Hybrid Resource or Energy Storage Resource Model Participant that is pool-scheduled or self-scheduled, has SCADA capability to transmit and receive instructions from the Office of the Interconnection, has provided data and established processes to follow PJM basepoints pursuant to the requirements for wind or solar generating units, Hybrid Resource or Energy Storage Resource Model Participant as further detailed in this Agreement, the Tariff and the PJM Manuals, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the real-time LMP at the unit's bus is higher than the unit's

offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the LOC Deviation times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C. An Energy Storage Resource Model Participant or a Hybrid Resource instructed to increase charging at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, shall be compensated for the increase in charging in the same manner as provided in sections 3.2.3(e). A unit in the Energy Storage Resource Participation Model or a Hybrid Resource instructed to reduce charging at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, is not eligible for compensation under section 3.2.3(f-4).

(f-5) If a Market Participant of an Energy Storage Resource Model Participant or a Hybrid Resource believes that the above calculations in this section 3.2.3 do not accurately compensate the Market Participant for opportunity costs associated with following PJM manual dispatch instructions to modify a unit's charging or discharging due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Participant will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Participant. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Participant accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-6) (i) A Market Seller of a pool-scheduled resource or a dispatchable self-scheduled resource shall receive Dispatch Differential Lost Opportunity Cost credits as calculated under subsection (iv) below if the resource is dispatched to provide energy in the Real-time Energy Market, provided such resource is not committed to provide real-time ancillary services (Regulation, reserves, reactive service) or instructed to reduce or suspend output due to a transmission constraint or other reliability issue pursuant to Operating Agreement, Schedule 1, section 3.2.3(f-1) through Operating Agreement, Schedule 1, section (f-4).

(ii) PJM will calculate the revenue above cost for the pricing run for each Real-time Settlement Interval in accordance with the following equation:

(A x B) - C

Where:

A = the resource's expected output level based on its resource parameters at the Real-time Price at the applicable pricing point;

B = the Real-time Price at the applicable pricing point; and

C = the sum of the resource's Real-time Energy Market offer integrated under the Final Offer for the resource's expected output level based on its resource parameters at the Real-time Price at the applicable pricing point.

(iii) PJM will calculate the revenue above cost for the dispatch run for each Real-time Settlement Interval in accordance with the following equation:

(greater of A and B) – (lesser of C and D)

Where:

A = the product of the amount of megawatts of energy dispatched in the Real-time Energy Market dispatch run for the resource in that Real-time Settlement Interval and the Real-time Price at the applicable pricing point;

B = the product of the amount of megawatts of energy the resource actually provided in that Real-time Settlement Interval and the Real-time Price at the applicable pricing point;

C = the resource's Real-time Energy Market offer integrated under the Final Offer for the amount of megawatts dispatched in the Real-time Energy Market dispatch run;

D = the resource's Real-time Energy Market offer integrated under the Final Offer for the amount of megawatts the resource actually provided in that Real-time Settlement Interval.

(iv) The Dispatch Differential Lost Opportunity Cost credit shall equal the greater of (A) the difference between the revenue above cost based on the pricing run determined in subsection (f-6)(ii) and the revenue above cost based on the dispatch run determined in subsection (f-6)(iii) or (B) zero.

(v) For each hour in an Operating Day, the total cost of the Dispatch Differential Lost Opportunity Cost credits shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load ((a) net of operating Behind The Meter Generation, but not to be less than zero; and (b) excluding Direct Charging Energy) in the PJM Region, served under Network Transmission Service, in megawatt-hours; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Operating Agreement, Schedule 1, section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(g) The sum of the foregoing credits in Operating Agreement, Schedule 1, section 3.2.3(f) through Operating Agreement, Schedule 1, section 3.2.3(f-5), plus any cancellation fees paid in accordance with Operating Agreement, Schedule 1, section 1.10.2(d), such cancellation

fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, plus any balancing Energy Make Whole Credits paid to pool-scheduled import transactions, less any payments received from another Control Area for energy uplift shall be allocated to each Market Participant's pro rata share of the daily total of hourly deviations in the RTO region, determined pursuant to Operating Agreement, Schedule 1, section 3.2.3(h). If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.11.6, the Office of the Interconnection shall allocate the charges to the pro rata share of the sum of its (i) deliveries of energy to load ((a) net of operating Behind The Meter Generation, but not to be less than zero; and (b) excluding Direct Charging Energy) in the PJM Region, served under Network Transmission Service, in megawatt-hours; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Operating Agreement, Schedule 1, section 1.12.

(h) Each Market Participant's daily total of hourly deviations are determined in accordance with the following equation:

$\sum_h (A + B + C)$

Where:

h = the hours in the applicable Operating Day;

A = For each Real-time Settlement Interval in an hour, the sum of the absolute value of the withdrawal deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy withdrawals (net of operating Behind The Meter Generation) in the Real-Time Energy Market, except as noted in subsection (h)(ii) below and in the PJM Manuals divided by the number of Real-time Settlement Intervals for that hour. The summation of each Real-time Settlement Interval's withdrawal deviation in an hour will be the Market Participant's total hourly withdrawal deviations. Market Participant bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Operating Agreement, Schedule 1, section 1.12 are not included in the determination of withdrawal deviations;

B = For each Real-time Settlement Interval in an hour, the sum of the absolute value of generation deviations (in MW and not including deviations in Behind The Meter Generation) as determined in subsection (o) divided by the number of Real-Time Settlement Intervals for that hour;

C = For each Real-time Settlement Interval in an hour, the sum of the absolute value of the injection deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy injections in the Real-Time Energy Market divided by the number of Real-time Settlement Intervals for that hour. The summation of the injection deviations for each Real-time Settlement Interval in an hour

will be the Market Participant's total hourly injection deviations. The determination of injection deviations does not include generation resources.

The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with Operating Agreement, Schedule 1, section 3.1A shall be used in determining the real-time withdrawal deviations, generation deviations and injection deviations under this subsection (h).

The foregoing notwithstanding, netting deviations shall be allowed for each Real-time Settlement Interval in accordance with the following provisions:

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions, which include the components referenced in Operating Agreement, Schedule 1, section 3.2.3(d) regarding the cost of Energy Make Whole credits in the Day-ahead Energy Market, at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

(iv) Bilateral transactions inside the PJM Region, as defined in Operating Agreement, Schedule 1, section 1.7.10, will not be included in the determination of supply or demand deviations.

Deviations as calculated above shall be deviations in the RTO region and shall be subject to charges for the RTO region determined in accordance with Operating Agreement, Schedule 1, section 3.2.3(q)(iii). Furthermore, deviations that occur within a single Zone shall be associated with the Eastern or Western region, as defined in Operating Agreement, Schedule 1, section 3.2.3(q) below, and shall be subject to charges determined for such region in accordance with Operating Agreement, Schedule 1, section 3.2.3(q)(iii). Deviations at a hub shall be associated with the Eastern or Western region if all the buses that define the hub are located in the region. Deviations at an Interface Pricing Point shall be associated with whichever region, the Eastern or Western region, with which the majority of the buses that define that Interface Pricing Point are most closely electrically associated. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to charges determined for such region in accordance with Operating Agreement, Schedule 1, section 3.2.3(q)(iii). Demand and supply

deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by buses that are wholly contained within the same Zone.

(i) At the end of each Operating Day, Market Sellers shall be credited for Condense Startup Cost and Condense Energy Use times the real-time LMP for synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in section 3.2.3(i) shall be the cost of energy uplift for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for the PJM Region.

(k) The cost of energy uplift for synchronous condensing for purposes other than providing Synchronized Reserve, Secondary Reserve, or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load ((a) net of operating Behind The Meter Generation, but not to be less than zero; and (b) excluding Direct Charging Energy) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Operating Agreement, Schedule 1, section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared ("Maximum Generation Emergency Alert"); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the Energy Make Whole credit otherwise provided by section 3.2.3.(b) or section 3.2.3(e-2) in connection with market-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as "MaxGen Conditions"). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Operating Agreement, Schedule 2, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Operating Agreement, Schedule 1, section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Operating Agreement, Schedule 1, section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Operating Agreement,

Schedule 1, section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh and greater than the Market Seller's lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Energy Make Whole. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Energy Make Whole for such Operating Day pursuant to section 3.2.3(e) plus the Real-time Energy Market revenues for the Real-time Settlement Intervals that the offer is economic divided by the megawatt hours of energy provided during the Real-time Settlement Intervals that the offer is economic. The Real-time Settlement Intervals that the offer is economic shall be: (i) the Real-time Settlement Intervals that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the Real-time Settlement Intervals in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any Real-time Settlement Intervals required due to the Minimum Run Time or other operating constraint of the unit, and (iii) for any unit with a Minimum Run Time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price for a market-based offer is greater than $1,000/MWh and greater than the Market Seller's lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Energy Make Whole. If notice of a MaxGen Condition is provided after 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Energy Make Whole determined in accordance with section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Energy Make Whole determined in accordance with section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Energy Make Whole for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Energy Make Whole for such Operating Day pursuant to section 3.2.3(b) divided by the

Specified Hours, plus the Day-ahead Price for such hour, and no Energy Make Whole payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) All generation resources shall be assessed deviations in accordance with the calculations described below and in the PJM Manuals.

Generation resource deviations are calculated as the difference between a resource's Actual MWh, (which for purposes of this section is defined as the Revenue Data for Settlements), and Tracking Ramp Limited Desired MWh for each Real-time Settlement Interval except for the scenarios where day-ahead scheduled MWh are used in the calculation as defined below.

A generation resource shall not be assessed deviations for the Real-time Settlement Interval if its deviation percentage <= 0.10 (10 percent).

$$Deviation\ Percentage = Abs\ [1 - \frac{Actual\ MWh}{Tracking\ Ramp\ Limited\ Desired\ MWh}\ ]$$

If the Actual MWh is equal to zero, the deviation percentage is equal to 1 (100 percent).

Generation resource deviations are calculated as the difference between a resource's Real-time Settlement Interval MWh and day-ahead scheduled MWh, rather than Tracking Ramp Limited Desired MWh, when a resource is non-dispatchable for any Real-time Settlement Interval. For purposes of this provision, a resource will be considered non-dispatchable when any of the following conditions occur:

- The generation resource is not dispatchable in the Day-ahead Energy Market and is not dispatchable in the Real-time Energy Market. For purposes of the generation resource deviation calculation, not dispatchable is defined as intervals when the minimum operating limit is equal to the maximum operating limit, or intervals when a generation resource elects to provide a fixed output using the fixed generation parameter, or other not dispatchable processes as defined in the PJM Manuals. All hydro resources are considered non-dispatchable unless operated as a dispatchable resource by the Office of the Interconnection.
- The self-scheduled generation resource is not dispatchable due to a limited dispatchable range. A dispatchable range is considered limited when the following equation is true:
    - Abs(maximum operating limit – minimum operating limit) <= 10% of Abs(minimum operating limit).
- The dispatchable self-scheduled generation resource has a Tracking Ramp Limited Desired MWh <= the minimum operating limit, except when the resource is desired at that level due to a Minimum Generation Emergency declaration or event.
- A generation resource is online and Tracking Ramp Limited Desired MWh is unable to be calculated due to unavailable schedules or offer parameters.

A generation resource shall not be assessed deviations for the Real-time Settlement Interval if its day-ahead deviation percentage is <= 0.05 (5%).

$$Day-ahead\ Deviation\ Percentage = Abs\ [1 - \frac{Actual\ MWh}{Day-ahead\ Scheduled\ MWh}\ ]$$

If the Actual MWh is equal to zero, the day-ahead deviation percentage is equal to 1 (100 percent).

A generation resource shall not be assessed deviations in a Real-time Settlement Interval if any of the following conditions occur for that interval:

- The resource is assigned pool-scheduled Regulation.
- The resource is assigned pool-scheduled Real-time Synchronized Reserves as a synchronous condenser.
- The resource is assigned pool-scheduled Real-time Secondary Reserves as a synchronous condenser.
- The resource is assigned pool-scheduled Real-time Non-Synchronized Reserves.
- The resource is assigned Real-time Synchronized Reserves and responded during a Synchronized Reserve Event.
- Flexible Resources that are committed in the Day-ahead Energy Market and not committed by the Office of the Interconnection in the Real-time Energy Market and the resource is offline.
- The resource is manually dispatched by the Office of the Interconnection and the manual instruction is not reflected in the Tracking Ramp Limited Desired MWh.

Deviations of generation resources with multiple units located at a single bus shall be netted for each Real-time Settlements Interval as described in Operating Agreement, Schedule 1, section 3.2.3(h)(i).

If a resource has an hourly average of the absolute value of generator deviations that is less than 5 MWh, then the resource shall not be assessed deviations for each Real-time Settlement Interval in that hour. This calculation shall be done after netting is applied, where applicable.

For the purpose of this section 3.2.3(o), a generation resource is considered to be following dispatch if it is not assessed deviations or has a deviation equal to zero in a Real-time Settlement Interval, as determined above and prior to any netting pursuant to section 3.2.3(h)(i) or for hourly averages pursuant to this section.

(o-1) Dispatchable economic load reduction resources that follow dispatch shall not be assessed deviations. Economic Load Response Participant resources that do not follow dispatch shall be assessed deviations as described in this subsection and as further specified in the PJM Manuals.

The Desired MW quantity for such resources for each hour shall be the hourly integrated MW quantity to which the load reduction resource was dispatched for each hour (where the hourly

integrated value is the average of the dispatched values as determined by the Office of the Interconnection for the resource for each hour).

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual reduction quantity) and charged as defined in Operating Agreement, Schedule 1, section 3.3A. For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined in Operating Agreement, Schedule 1, section 3.3A. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall apply any balancing Energy Make Whole credits determined pursuant to Operating Agreement, Schedule 1, section 3.2.3(e-2), except those associated with the scheduling of units for Black Start Service or testing of Black Start Service units as provided in Tariff, Schedule 6A, to deviations determined pursuant to section 3.2.3(h) or real-time load plus exports depending on whether the underlying balancing Energy Make Whole credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Energy Make Whole credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Energy Make Whole credits, identified as reliability analysis credits for deviations, shall be allocated to deviations determined pursuant to Operating Agreement, Schedule 1, section 3.2.3(h).

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Energy Make Whole credits, identified as reliability analysis credits for reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Energy Make Whole credits shall be identified

in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(p)(i)(A) and 3.2.3(p)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Energy Make Whole credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Energy Make Whole credits, identified as real-time credits for reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceeds the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (real-time credits for reliability or real-time credits for deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Operating Agreement, Schedule 1, section 3.2.3(p)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Energy Make Whole credits, identified as real-time credits for deviations, shall be allocated to deviations determined pursuant to Operating Agreement, Schedule 1, section 3.2.3(h).

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in Operating Agreement, Schedule 1, sections 3.2.3(p)(i) and (p)(ii).

The costs associated with scheduling of units for Black Start Service or testing of Black Start Service units shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zonal load or non-Zonal load, as determined in accordance with the formulas contained in Tariff, Schedule 6A.

(q) (i) Balancing Energy Make Whole credits for reliability or deviations as determined in Operating Agreement, Schedule 1, section 3.2.3(p) shall be assigned to the Eastern or Western region if the credit paid to the generator is due to transmission constraints that occur on transmission system capacity equal to or less than 345kv. Balancing Energy Make Whole credits for reliability or deviations not assigned to the Eastern or Western region shall be assigned to the RTO region. For the purposes of this section, the Western region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, DEOK, EKPC, OVEC transmission Zones, and the Eastern region shall be the AEC,

BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones.

(ii) The total balancing Energy Make Whole credits for reliability in each region shall be allocated as charges to each Market Participant's pro rata share of real-time load plus export transactions in such region. For purposes of this Operating Agreement, Schedule 1, section 3.2.3(q), a Market Participant's real-time load plus export transactions shall be equal to the daily total of (i) real-time deliveries of energy to load in the relevant region ((a) net of operating Behind The Meter Generation, but not to be less than zero; and (b) excluding Direct Charging Energy), served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) real-time deliveries of energy sales from within the PJM Region to load outside the PJM Region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Operating Agreement, Schedule 1, section 1.12.

(iii) The total balancing Energy Make Whole credits for deviations in the Eastern region and the Western region shall be allocated as charges to each Market Participant's pro rata share of the daily total of hourly deviations in the relevant region as determined pursuant to Tariff, Operating Agreement, Schedule 1, section 3.2.3(h). The total balancing Energy Make Whole credits for deviations in the RTO region plus the total credits as determined in Operating Agreement, Schedule 1, section 3.2.3(g) shall be allocated as charges to each Market Participant's pro rata share of the daily total of hourly deviations in the RTO region as determined pursuant to Operating Agreement, Schedule 1, section 3.2.3(h). If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.11.6, the Office of the Interconnection shall allocate deviation charges to the ratio share of real-time load plus export transactions pursuant to Operating Agreement, Schedule 1, section 3.2.3(q)(ii).

(q-1) (i) Regional balancing uplift rates shall be determined in accordance with the following provisions:

The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western regions. Regional adder rates for reliability shall be equal to the total balancing Energy Make Whole credits for reliability in the region divided by the total real-time load plus export transactions in the relevant region in accordance with Operating Agreement, Schedule 1, section 3.2.3(q)(ii). Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with Operating Agreement, Schedule 1, section 3.2.3(p).

Regional adder rates for deviations shall be equal to the total balancing Energy Make Whole credits for deviations in the region divided by the daily total of hourly deviations in the relevant region in accordance with Operating Agreement, Schedule 1, section 3.2.3(q)(iii).

(ii) The Office of the Interconnection shall calculate RTO balancing uplift rates. RTO balancing uplift rates for reliability shall be equal to the total balancing Energy Make Whole credits for reliability in the RTO region divided by the total real-time load plus export transactions in the RTO region in accordance with section (q)(ii). RTO balancing uplift rates for deviations shall be equal to the total balancing Energy Make Whole credits for deviations in the RTO region plus the total credits as determined in Operating Agreement, Schedule 1, section 3.2.3(g) divided by the daily total of hourly deviations in the RTO region as determined pursuant to Operating Agreement, Schedule 1, section 3.2.3(h). Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Operating Agreement, Schedule 1, section 3.2.3(p).

(iii) Reliability and deviation regional balancing uplift rates shall be determined by summing the relevant RTO balancing Energy Make Whole rates and regional adder rates.

(r) Market Sellers that incur incremental operating costs for a generation resource that are either greater than $1,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Operating Agreement, Schedule 2 and PJM Manual 15, but are not verified at the time of dispatch of the resource under Operating Agreement, Schedule 1, section 6.4.3, or greater than $2,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Operating Agreement, Schedule 2, and PJM Manual 15, will be eligible to receive credit for Energy Make Whole upon review of the Market Monitoring Unit and the Office of the Interconnection, and approval of the Office of the Interconnection. Market Sellers must submit to the Office of the Interconnection and the Market Monitoring Unit all relevant documentation demonstrating the calculation of costs greater than $2,000/MWh, and costs greater than $1,000/MWh which were not verified at the time of dispatch of the resource under Operating Agreement, Schedule 1, section 6.4.3. The Office of the Interconnection must approve any Energy Make Whole credits paid to a Market Seller under this subsection (r).

3.2.3A Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant's hourly Synchronized Reserve Obligation shall be adjusted by any Synchronized Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Synchronized Reserve Obligation shall

be charged the pro rata share of the sum of day-ahead and real-time credits for Synchronized Reserve as defined in sections 3.2.3A(b)(i) and (ii) below.

(b) A resource supplying Synchronized Reserve at the direction of the Office of the Interconnection shall be credited as follows:

i) Credits for Synchronized Reserve provided by generation and Economic Load Response Participant resources assigned to provide Synchronized Reserve by the Office of the Interconnection or self-scheduled in the Day-ahead Synchronized Reserve Market shall be equal to the product of the Day-ahead Synchronized Reserve Market Clearing Price multiplied by the megawatt amount of Synchronized Reserve such resource is assigned to provide..

ii) Credits for Synchronized Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Synchronized Reserve by the Office of the Interconnection or self-scheduled in the Real-time Synchronized Reserve Market shall be determined for each operating hour based on the sum of their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$\sum_i ((A - B) * C)$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Synchronized Reserve from that resource assigned by the Office of the Interconnection or self-scheduled in the Real-time Synchronized Reserve Market. The megawatt value is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval where there is not a Synchronized Reserve event;

B = For each Real-time Settlement Interval, the megawatts of Synchronized Reserve from that resource assigned by the Office of the Interconnection or self-scheduled in the Day-ahead Synchronized Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Synchronized Reserve Market Clearing Price.

If a Synchronized Reserve Event is initiated by the Office of the Interconnection and the Economic Load Response Participant resource reduced its load in response to the event, the resource shall be eligible to receive a credit for the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

iii) Pool-scheduled resources shall be credited a Synchronized Reserve lost opportunity cost credit, where positive, as described in subsection (f)(iv) below.

(c) [Reserved for future use]

(d) Synchronized Reserve Market Clearing Prices

(i) For the Day-ahead Synchronized Reserve Market, the Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Synchronized Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for Synchronized Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Synchronized Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Synchronized Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Synchronized Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute and (B) the price of serving the next increment of demand for Primary Reserve and 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute, provided that the Synchronized Reserve Market Clearing Price shall be less than or equal to the sum of no more than two of the Reserve Penalty Factors for the Synchronized Reserve Requirement, the Primary Reserve Requirement, and the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.10.8(d), Day-ahead Synchronized Reserve Market Clearing Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and Day-ahead Synchronized Reserve Market Clearing Price of zero dollars per megawatt-hour and all settlements will be based on the Real-time Synchronized Reserve market quantities and prices as determined pursuant to subsection (d)(ii) hereof.

(ii) For the Real-time Synchronized Reserve Market, the Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for Synchronized Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Synchronized Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Synchronized Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve

Sub-zone, plus (A) the price of serving the next increment of demand for Synchronized Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute and (B) the price of serving the next increment of demand for Primary Reserve and 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute, provided that the Synchronized Reserve Market Clearing Price shall be less than or equal to the sum of no more than two of the Reserve Penalty Factors for the Synchronized Reserve Requirement, the Primary Reserve Requirement, and the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Synchronized Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, and the Office of the Interconnection is not assigning Synchronized Reserves, then the Synchronized Reserve Market Clearing Price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, where the real-time Market Suspension is less than or equal to six (6) consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Synchronized Reserves, then the Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Synchronized Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than six (6) consecutive hours but less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating Days, and there are cleared Day-ahead Synchronized Reserve Market Clearing Prices for the affected Operating Day, then the Real-time Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the Day-ahead Synchronized Reserve Market Clearing Prices for each corresponding hour. If no such Day-ahead Synchronized Reserve Market Clearing Prices exist, then the Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Synchronized Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than twenty-four (24) consecutive hours, and the Office of the Interconnection is assigning Synchronized Reserves, the Office of the Interconnection will set the Synchronized Reserve Market Clearing Price to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period. Resources will be compensated for lost opportunity cost per subsection (f) hereof using the energy price as determined in Operating Agreement, Schedule 1, section 2.5.2.iii. The opportunity cost shall be zero for all resources self-scheduled to provide Synchronized Reserve, synchronous condensers and Economic

Load Response Participant resources.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Synchronized Reserve Market Clearing Price shall be the sum of the Reserve Penalty Factors for the Primary Reserve Requirement, and the Synchronized Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

(iii) The Reserve Penalty Factor for the Synchronized Reserve Requirement shall be $850/MWh.

The Reserve Penalty Factor for the Extended Synchronized Reserve Requirement shall be $300/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Synchronized Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(e) (i) For determining the Synchronized Reserve Market Clearing Price in each hour of the Day-ahead Synchronized Reserve Market, the estimated resource-specific opportunity cost for a generation resource or Economic Load Response Participant resource shall be the difference between the Locational Marginal Price at the generation or Economic Load Response Participant resource bus and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) or offer price to reduce energy from the Economic Load Response Participant resource in the PJM Interchange Energy Market when the Locational Marginal Price at the generation or Economic Load Participant resource bus is greater than the offer price for energy from the generation resource or the offer price to reduce energy from the Economic Load Response Participant resource.

However, the opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve and for synchronous condensers and for Economic Load Response Participant resources that do not receive a day-ahead commitment to provide energy in the same operating hour in which such resource is committed to provide Synchronized Reserve.

(ii) For determining the Synchronized Reserve Market Clearing Price for each Real-time Settlement Interval in the Real-time Synchronized Reserve Market, the estimated unit-specific opportunity cost for a generation resource that is not a hydroelectric resource shall be the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource)

in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

For hydroelectric resources, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions, as defined in the PJM Manuals, and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

The opportunity costs shall be zero for all resources self-scheduled to provide Synchronized Reserve, synchronous condensers and Economic Load Response Participant resources.

(f) (i) In determining the credit under subsection (b) to a generation resource, except a generation resource that is operating as a synchronous condenser, selected to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market, or an Economic Load Response Participant resource that is selected to provide Synchronized Reserve in the Day-ahead Synchronized Reserve Market for the same operating hour in which such resource receives a day-ahead commitment to provide energy, the opportunity cost of a resource shall be determined for each operating hour that the Office of the Interconnection requires a resource to provide Synchronized Reserve and shall be in accordance with the following equation:

(A x B) - C

Where:

A = The Day-ahead Locational Marginal Price at the generation bus of the generation resource or the applicable pricing point for the Economic Load Response Participant resource;

B = The deviation of the resource's energy output or load reduction necessary to supply a Day-ahead Synchronized Reserve assignment from the resource's energy expected output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load; and

C = The Day-ahead Energy market offer integrated under the applicable energy offer curve for the resource's energy output or load reduction necessary to provide a Day-ahead Synchronized Reserve Market assignment from the resource's expected energy

output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load.

For a generation resource that is operating as a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [Condense Energy Use multiplied by A] plus [the applicable Condense Startup Cost divided by the number of hours the resource is assigned Synchronized Reserve].

(ii) In determining the credit under subsection (b) to a generation resource, except a generation resource that is operating as a synchronous condenser, selected to provide Synchronized Reserve in the Real-time Synchronized Reserve Market in excess of the resource's Day-ahead Synchronized Reserve Market assignment and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of that generation resource shall be determined for each Real-time Settlement Interval that the Office of the Interconnection requires that generation resource to provide Synchronized Reserve and shall be in accordance with the following equation:

(A x B) - C

Where:

A = The Real-time Locational Marginal Price at the generation bus of the generation resource;

B = The deviation of the generation resource's output necessary to supply Synchronized Reserve in real-time, reduced by the amount of Synchronized Reserve the resource failed to respond during a Synchronized Reserve Event during the Operating Day, in excess of its Day-ahead Synchronized Reserve Market assignment and follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy; and

C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Synchronized Reserve in real-time from the lesser of the generation resource's output necessary to provide a Day-ahead Synchronized Reserve Market assignment or follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [additional Condense Energy Use in excess of day-ahead Condense Energy Use in real-time multiplied by A] plus [any applicable Condense Startup Cost due to additional Condense Startup Cost in real-time in excess of day-ahead Condense Startup Cost allocated to each Real-time Settlement Interval as described in PJM Manuals].

For hydroelectric resources, the unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the real-time Locational Marginal Price at that generation bus multiplied by the additional megawatts assigned to supply Synchronized Reserve in real-time in excess of its Day-ahead Synchronized Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average real-time Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating multiplied by the additional megawatts assigned to supply the hourly Synchronized Reserve in real-time in excess of its Day-ahead Synchronized Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

(iii) For each Real-time Settlement Interval, a Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in the resource's real-time reserve MW from a day-ahead market assignment in more than one market for that Real-time Settlement Interval, the total Market Revenue Neutrality Offset is allocated to the Synchronized Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Synchronized Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Synchronized Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Synchronized Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Synchronized Reserve assignment decreases due to the resource being self-scheduled to provide energy or Regulation;

(B) A resource reduces its flexibility in real-time such that the resource no longer qualifies to provide Synchronized Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time;

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above; or

(F) A resource increases its Synchronized Reserve offer price in the Real-time Synchronized Reserve Market from its offer price in the Day-ahead Synchronized Reserve Market.

(iv) A Synchronized Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

(A + B + C + D) – (E + F + G + H)

Where:

A = day-ahead Synchronized Reserve offer price times the Synchronized Reserve MW assignment;

B = real-time Synchronized Reserve offer price times the Synchronized Reserve MW assigned in real-time in excess of the Synchronized Reserve MW assigned day-ahead, where the Synchronized Reserve MW assigned is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval where there is not a Synchronized Reserve event;

C = day-ahead opportunity cost as determined in subsection (f)(i) above;

D = real-time opportunity cost as determined in subsection (f)(ii) above;

E = day-ahead clearing price credits as determined in subsection (b)(i) above;

F = real-time clearing price credits as determined in subsection (b)(ii) above less any applicable charges for failure to respond to a Synchronized Reserve Event as determined in subsection (j) below;

G = the applicable Market Revenue Neutrality Offset as determined in subsection (f)(iii) above; and

H = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A(f)(iii) above if not eligible for Market Revenue Neutrality Offset.

(v) The opportunity costs for an Economic Load Response Participant resource assigned Synchronized Reserve in real-time or any resource self-scheduled for Synchronized Reserves shall be zero.

(g) [Reserved for future use]

(h) For each operating hour, the sum of the Synchronized Reserve lost opportunity cost credits credited in accordance with subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Synchronized Reserve Obligation in proportion to its real-time purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) [Reserved for future use]

(j) In the event a generation resource or Economic Load Response Participant Resource that either has been assigned by the Office of the Interconnection or self-scheduled to provide Synchronized Reserve in real-time fails to provide the amount of Synchronized Reserve it was directed to deploy in response to a Synchronized Reserve Event, the resource will be charged at the Real-time Synchronized Reserve Market Clearing Price for the real-time Synchronized Reserve the resource was directed to deploy, in excess of the amount that actually responded for all Real-time Settlement Intervals the resource was assigned or self-scheduled Synchronized Reserve real-time. For each Real-time Settlement Interval where there is not a Synchronized Reserve Event, the megawatts that will be charged shall be the lesser of the amount of the shortfall of Synchronized Reserve, measured in megawatts, or the real-time Synchronized Reserve assignment, which is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements for the resource on the Operating Day during which the event occurred. The determination of the amount of Synchronized Reserve credited to a resource shall be on an individual resource basis, not on an aggregate basis.

The resource shall refund payments received for Synchronized Reserve it failed to provide. For purposes of determining the amount of the payments to be refunded by a Market Participant, the Office of the Interconnection shall calculate the shortfall of Synchronized Reserve on an individual resource basis unless the Market Participant had multiple resources that were assigned or self-scheduled to provide Synchronized Reserve, in which case the shortfall will be determined on an aggregate basis. For performance determined on an aggregate basis, the response of any resource that was assigned or self-scheduled for Synchronized Reserve and provided more Synchronized Reserve than it was directed to deploy will be used to offset the performance of other resources that provided less assigned or self-scheduled Synchronized Reserve than they were directed to deploy during a Synchronized Reserve Event, as calculated in the PJM Manuals. The determination of a Market Participant's aggregate response shall not be taken into consideration in the determination of the amount of Synchronized Reserve credited to each individual resource.

The amount refunded shall be determined by multiplying the retroactive penalty megawatts by the Real-time Synchronized Reserve Market Clearing Price for all intervals the resource was assigned or self-scheduled to provide Synchronized Reserve for a period of time immediately preceding the Synchronized Reserve Event equal to the lesser of the average number of days between Synchronized Reserve Events, or the number of days since the resource last failed to provide the amount of Synchronized Reserve it was directed to deploy in response to a Synchronized Reserve Event. The retroactive penalty megawatts for each interval shall be the lesser of the amount of the shortfall of Synchronized Reserve, measured in megawatts, and the

real-time Synchronized Reserve assignment for each interval, which is capped at the lesser of the Economic Maximum and the Synchronized Reserve maximum MW minus the Revenue Data for Settlements for the resource. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following January 1. The refunded charges shall be allocated as credits to Market Participants based on its pro rata share of the Synchronized Reserve Obligation megawatts in the hour(s) of the Synchronized Reserve Event for the Reserve Sub-zone or Reserve Zone, except that Market Participants that incur a refund obligation and also have an applicable Synchronized Reserve Obligation during the hour(s) of the Synchronized Reserve Event shall not be included in the allocation of such refund credits. If the event spans multiple hours, the refund credits will be prorated hourly based on the duration of the event within each clock hour.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or an Economic Load Response Participant resource, except for Batch Load Economic Load Response Participant resources covered by section 3.2.3A(l), is the difference between the generation resource's output or the Economic Load Response Participant resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Economic Load Response Participant resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Economic Load Response Participant resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or an Economic Load Response Participant resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Economic Load Response Participant resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to an Economic Load Response Participant resource will be reduced by the amount the megawatt consumption of the Economic Load Response Participant resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Economic Load Response Participant resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load Economic Load Response Participant resource's consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Economic Load Response Participant resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Economic Load Response Participant resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in

such minute; provided that, the magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant's hourly Non-Synchronized Reserve Obligation shall be adjusted by any Non-Synchronized Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Non-Synchronized Reserve Obligation shall be charged the pro rata share of the sum day-ahead and real-time credits for Non-Synchronized Reserve as defined in sections 3.2.3A.001(b)(i) and (ii) below.

(b) Resources assigned to provide Non-Synchronized Reserve at the direction of the Office of the Interconnection shall be credited as follows:

(i) Credits for Non-Synchronized Reserve provided by generation resources assigned to provide Non-Synchronized Reserve by the Office of the Interconnection in the Day-ahead Non-Synchronized Reserve Market shall be equal to the product of the Day-ahead Non-Synchronized Market Clearing Price multiplied by the megawatt amount of Non-Synchronized Reserve such resource is assigned to provide.

(ii) Credits for Non-Synchronized Reserve provided by generation resources assigned to provide Non-Synchronized Reserve by the Office of the Interconnection in the Real-time Non-Synchronized Reserve Market shall be determined for each operating hour based on the sum on their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$$\sum_i ((A - B) * C)$$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Non-Synchronized Reserve from that resource assigned by the Office of the Interconnection in the Real-time Non-Synchronized Reserve Market;

B = For each Real-time Settlement Interval, the megawatts of Non-Synchronized Reserve from that resource assigned by the Office of the Interconnection in the Day-ahead Non-Synchronized Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Non-Synchronized Reserve Market Clearing Price.

(iii) Pool-scheduled generation resources assigned to provide Non-Synchronized Reserve in the Day-ahead Non-Synchronized Reserve Market shall be credited a Non-Synchronized Reserve lost opportunity cost credit, where positive, as determined in accordance with subsection (d)(iii) below, to recover any net monetary loss to the Market Seller of such resource associated with the purchase of Non-Synchronized Reserve in the Real-time Non-Synchronized Reserve Market as a result of following the dispatch direction of the Office of the Interconnection.

(c) Non-Synchronized Reserve Market Clearing Prices

(i) For the Day-ahead Non-Synchronized Reserve Market, the Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Non-Synchronized Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for Primary Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Non-Synchronized Reserve offer prices and the applicable Operating Reserve Demand Curve for Non-Synchronized Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Primary Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute and (B) the price of serving the next increment of demand for 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute, provided that the Non-Synchronized Reserve Market Clearing Price shall be less than or equal to the product of 1.5 multiplied by the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Non-Synchronized Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.10.8(d), Day-ahead Non-Synchronized Reserve Market Clearing Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and Day-ahead Non-Synchronized Reserve Market Clearing Price of zero dollars per megawatt-hour and all settlements will be based on the Real-time Non-Synchronized Reserve market quantities and prices as determined pursuant to subsection (c)(ii) hereof.

(ii) For the Real-time Non-Synchronized Reserve Market, the Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for Primary Reserve in a Reserve Zone or Reserve Sub-zone determined by the interaction between a supply curve formed using Non-Synchronized Reserve offer prices and the applicable Operating Reserve Demand Curve for Non-Synchronized Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus (A) the price of serving the next increment of demand for Primary Reserve for any other Reserve Zone or Reserve Subzone to which the next increment of demand for Primary Reserve can contribute and (B) the price of serving the next increment of demand for 30-minute Reserve for each Reserve Zone or Reserve Sub-zone to which the next increment of demand for Primary Reserve can contribute, provided that the Non-Synchronized Reserve Market Clearing Price shall be less than or equal to the product of 1.5 multiplied by the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for Non-Synchronized Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, and the Office of the Interconnection is not assigning Non-Synchronized Reserves, then the Non-Synchronized Reserve Clearing Price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, where the real-time Market Suspension is less than or equal to six (6) consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Non-Synchronized Reserves, then the Non-Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Non-Synchronized Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than six (6) consecutive hours but less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating Days, and there are cleared Day-ahead Non-Synchronized Reserve Market Clearing Prices for the affected Operating Day, then the Real-time Non-Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the Day-ahead Non-Synchronized Reserve Market Clearing Prices for each corresponding hour. If no such Day-ahead Non-Synchronized Reserve Market Clearing Prices exist, then the Non-Synchronized Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Non-Synchronized Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than twenty-four (24) consecutive hours, the Non-Synchronized Reserve Market Clearing Price will be set to zero dollars per megawatt-hour regardless of whether the Office of the Interconnection is assigning Non-Synchronized Reserves.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Non-Synchronized Reserve Market Clearing Price shall be the product of 1.5 multipled by the Reserve Penalty Factor for the Primary Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

(iii) The Reserve Penalty Factor for the Primary Reserve Requirement shall be $850/MWh.

The Reserve Penalty Factor for the Extended Primary Reserve Requirement shall be $300/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Primary Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(d) (i) For determining the Non-Synchronized Reserve clearing price for each hour in the Day-ahead Non- Synchronized Reserve Market and for each Real-time Settlement Interval in the Real-time Non-Synchronized Reserve Market, including during a declaration of a Market Suspension, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves will be zero.

(ii) For each Real-time Settlement Interval, a total Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in real-time reserve MW from a day-ahead market assignment in more than one market for that Real-time Settlement Interval, the total Market Revenue Neutrality Offset is allocated to the Non-Synchronized Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Non-Synchronized Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Non-Synchronized Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Non-Synchronized Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Non-Synchronized Reserve assignment decreases due to the resource being self-scheduled to provide energy, Synchronized Reserve, or Regulation;

(B) A resource reduces flexibility in real-time such that the resource no longer qualifies to provide Non-Synchronized Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time; or

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above.

(iii) A Non-Synchronized Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

(zero) – (A + B + C + D)

Where:

A = day-ahead clearing price credits as determined in subsection (b)(i) above;

B = real-time clearing price credits as determined in subsection (b)(ii) above;

C = the applicable Market Revenue Neutrality Offset as determined in subsection (d)(ii) above; and

D = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A.001(d)(ii) above if not eligible for Market Revenue Neutrality Offset.

(e) [Reserved for future use]

(f) For each operating hour, the sum of the Non-Synchronized Reserve lost opportunity cost credits credited in subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation in proportion to its real-time purchases of Non-Synchronized Reserve in megawatt-hours during that hour.

(g) The magnitude of response to a Non-Synchronized Reserve Event by a generation resource is the difference between the generation resource's output at the start of the event and

its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output at the start of the event is defined as the lowest telemetered generator resource output between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output 10 minutes after the start of the event is defined as the greatest generator resource output achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(h) In the event a generation resource that has been assigned by the Office of the Interconnection to provide Non-Synchronized Reserve fails to provide the assigned amount of Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the contiguous Real-time Settlement Interval the resource was assigned Non-Synchronized Reserve during which the event occurred.

3.2.3A.01 Secondary Reserve.

(a) Each Market Participant that is a Load Serving Entity shall have an obligation for hourly Secondary Reserve equal to its pro rata share of Secondary Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Secondary Reserve Obligation"). A Market Participant's hourly Secondary Reserve Obligation shall be adjusted by any Secondary Reserve provided on the Market Participant's behalf through a bilateral agreement. A Market Participant with an hourly Secondary Reserve Obligation shall be charged the pro rata share of the sum of day-ahead and real-time credits for Secondary Reserve as defined in sections 3.2.3A.01(b)(i) and (ii) below.

(b) Resources assigned to provide Secondary Reserve at the direction of the Office of the Interconnection shall be credited as follows:

(i) Credits for Secondary Reserve provided by generation resources and Economic Load Response Participant resources assigned to provide Secondary Reserve by the Office of the Interconnection in the Day-ahead Secondary Reserve Market shall be equal to the product of the Day-ahead Secondary Reserve Market Clearing Price multiplied by the megawatt amount of Secondary Reserve such resource is scheduled to provide.

(ii) Credits for Secondary Reserve provided by generation resources and Economic Load Response Participant resources scheduled to provide Secondary Reserve by the Office of the Interconnection in the Real-time Secondary Reserve Market shall be determined for each operating hour based on the sum of their hourly total of Real-time Settlement Interval deviations determined in accordance with the following equation:

$\sum_i ((A - B) * C)$

Where:

i = the Real-time Settlement Intervals in the applicable operating hour;

A = For each Real-time Settlement Interval, the megawatts of Secondary Reserve from that resource assigned by the Office of the Interconnection in the Real-time Secondary Reserve Market. The megawatt value is capped at the lesser of the Economic Maximum or Secondary Reserve maximum MW minus the Revenue Data for Settlements of the resource for each Real-time Settlement Interval minus the Real-time Synchronized Reserve assignment;

B = For each Real-time Settlement Interval, the megawatts of Secondary Reserve from that resource scheduled by the Office of the Interconnection in the Day-ahead Secondary Reserve Market; and

C = For each Real-time Settlement Interval, the Real-time Secondary Reserve Market Clearing Price.

(iii) Pool-scheduled resources and Economic Load Response Participant resources shall be credited a Secondary Reserve lost opportunity cost credit, where positive, as described in subsection (f)(iv) below.

(c) [Reserved for future use]

(d) Secondary Reserve Market Clearing Prices

(i) For the Day-ahead Secondary Reserve Market, the Secondary Reserve Market Clearing Price shall be determined for each Reserve Zone and, as applicable, Reserve Sub-zone by the Office of the Interconnection for each hour of the Operating Day. The Day-ahead Secondary Reserve Market Clearing Price shall be calculated as the price of serving the next increment of demand for 30-minute Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Secondary Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Secondary Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus the price of serving the next increment of demand for 30-minute Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute, but the Secondary Reserve Market Clearing Price shall not exceed the Reserve Penalty Factor for the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, per Operating Agreement, Schedule 1, section 1.10.8(d), Day-ahead Secondary Reserve Market

Clearing Prices shall be set to zero dollars per megawatt-hour and for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and Day-ahead Secondary Reserve Market Clearing Price of zero dollars per megawatt-hour and all settlements will be based on the Real-time Secondary Reserve market quantities and prices as determined pursuant to subsection (d)(ii) hereof.

(ii) For the Real-time Secondary Reserve Market, the Secondary Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each Real-time Settlement Interval of the Operating Day. Each 5-minute clearing price shall be calculated as the price of serving the next increment of demand for 30-minute Reserve in a Reserve Zone or Reserve Sub-zone, determined by the interaction between a supply curve formed using Secondary Reserve offer prices and opportunity costs and the applicable Operating Reserve Demand Curve for Secondary Reserve established in accordance with Operating Agreement, Schedule 1, section 3.2.3A.02 for that Reserve Zone or Reserve Sub-zone, plus the price of serving the next increment of demand for 30-minute Reserve for any other Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute but the Secondary Reserve Market Clearing Price shall not exceed the Reserve Penalty Factor for the 30-minute Reserve Requirement for the Reserve Zone or Reserve Sub-zone to which the next increment of demand for 30-minute Reserve can contribute.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, and the Office of the Interconnection is not assigning Secondary Reserves, then the Secondary Reserve Clearing Price will be set to zero dollars per megawatt-hour for all Real-time Settlement Intervals in the Market Suspension period.

If the Office of the Interconnection declares a Market Suspension, as per Operating Agreement, Schedule 1, section 2.5.2, where the real-time Market Suspension is less than or equal to six (6) consecutive hours, which may span up to two Operating Days, and the Office of the Interconnection is assigning Secondary Reserves, then the Secondary Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Secondary Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than six (6) consecutive hours but less than or equal to twenty-four (24) consecutive hours, which may span up to two Operating Days, and there are cleared Day-ahead Secondary Reserve Market Clearing Prices for the affected Operating Day, then the Real-time Secondary Reserve Market Clearing Prices associated with such Market Suspension shall be the Day-ahead Secondary Reserve Market Clearing Prices for each corresponding hour. If no such Day-ahead Secondary Reserve Market Clearing Prices exist, then the Secondary Reserve Market Clearing Prices associated with such Market Suspension shall be the average of the Secondary

Reserve Market Clearing Prices for all Real-time Settlement Intervals of the preceding and subsequent clock hours (from XX:00 to XX:59) adjacent to such Market Suspension.

If the real-time Market Suspension is greater than twenty-four (24) consecutive hours, and the Office of the Interconnection is assigning Secondary Reserves, the Secondary Reserve Market Clearing Price will be set to zero dollars per megawatt-hour. Resources will be compensated for lost opportunity cost per subsection (f) hereof using the energy price as determined in Operating Agreement, Schedule 1, section 2.5.2.iii.

If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action or a Manual Load Dump Action as described in the PJM Manuals, the Real-time Secondary Reserve Market Clearing Price for a given Reserve Zone or Sub-zone shall be the Reserve Penalty Factor for the 30-minute Reserve Requirements for that Reserve Zone or Reserve Sub-zone .

(iii) The Reserve Penalty Factor for the 30-minute Reserve Requirement shall be $850/MWh.

The Reserve Penalty Factor for the Extended 30-minute Reserve Requirement shall be $300/MWh.

(iv) By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Reserve Penalty Factor for 30-minute Reserve are warranted for subsequent Delivery Year(s).

(e) (i) For determining the Secondary Reserve Market Clearing Price for each hour in the Day-ahead Secondary Reserve Market, the estimated resource-specific opportunity cost for a generation resource or Economic Load Response Participant resources shall be the difference between the Locational Marginal Price at the generation or Economic Load Response Participant resource bus and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) or offer price to reduce energy from the Economic Load Response Participant resource in the PJM Interchange Energy Market when the Locational Marginal Price at the Economic Load Response Participant resource bus is greater than the offer price for energy from the generation resource or the offer price to reduce energy from the Economic Load Response Participant resource.

However, opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve, and for synchronous condensers and for Economic Load Response Participant resources that do not receive a day-ahead commitment to provide energy in the same operating hour in which such resource is committed to provide Secondary Reserve.

(ii) For determining the Secondary Reserve Market Clearing Price for each Real-time Settlement Interval in the Real-time Secondary Reserve Market, the estimated

unit-specific opportunity cost for a generation resource that is not a hydroelectric resource shall be the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the energy dispatch point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

For hydroelectric resources, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the expected real-time Locational Marginal Price at that generation bus. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the expected real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average day-ahead Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

However, the opportunity costs shall be zero for resources self-scheduled to provide Synchronized Reserve, and for synchronous condensers and Economic Load Response Participant resources.

(f) (i) In determining the credit under subsection (b) to a generation resource, except a generation resource that is a synchronous condenser, selected to provide Secondary Reserve in the Day-ahead Secondary Reserve Market or an Economic Load Response Participant resource that is selected to provide Secondary Reserve in the Day-ahead Secondary Reserve Market in the same operating hour in which such resource receives a day-ahead commitment to provide energy, the opportunity cost of a resource shall be determined for each operating hour that the Office of the Interconnection requires a resource to provide Secondary Reserve and shall be in accordance with the following equation:

(A x B) – C

Where:

A = The Day-ahead Locational Marginal Price at the generation bus of the generation resource or the applicable pricing point for the Economic Load Response Participant resource;

B= The deviation of the resource's energy output or load reduction necessary to supply a Day-ahead Secondary Reserve assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit

order to provide energy or reduce load less any Day-ahead Synchronized Reserve Market assignment; and

C = The Day-ahead Energy Market offer integrated under the applicable energy offer curve for the resource's energy output or load reduction necessary to provide a Day-ahead Secondary Reserve Market assignment from the resource's expected energy output or load reduction level if it had been assigned in economic merit order to provide energy or reduce load less any Day-ahead Synchronized Reserve Market assignment.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: [Condense Energy Use multiplied by A] plus [the applicable Condense Startup Cost divided by the number of hours the resource is assigned Secondary Reserve].

(ii) In determining the credit under subsection (b) to a generation resource, except a generation that is a synchronous condenser, selected to provide Secondary Reserve in the Real-time Secondary Reserve Market in excess of the resource's Day-ahead Secondary Reserve Market assignment and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of that generation resource shall be determined for each Real-time Settlement Interval that the Office of the Interconnection requires that generation resource to provide Secondary Reserve and shall be in accordance with the following equation:

(A x B) – C

Where:

A = The Real-time Locational Marginal Price at the generation bus of the generation resource;

B= The deviation of the generation resource's output necessary to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment and follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy less any Real-time Synchronized Reserve Market assignment; and

C = The energy offer integrated under the applicable energy offer curve for the generation resource's output necessary to supply Secondary Reserve in real-time from the lesser of the generation resource's output necessary to provide a Day-ahead Secondary Reserve Market assignment or follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order to provide energy less any Real-time Synchronized Reserve Market assignment.

For hydroelectric resources, the unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the real-time Locational Marginal Price at that generation bus multiplied by the additional megawatts assigned to supply Synchronized Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead energy commitment greater than zero shall be the greater of zero and the difference between the real-time Locational Marginal Price at the generation bus for the hydroelectric resource and the average real-time Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating multiplied by the additional megawatts assigned to supply Secondary Reserve in real-time in excess of its Day-ahead Secondary Reserve Market assignment.

The unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead energy commitment greater than zero shall be zero.

For a generation resource that is a synchronous condenser, the resource's unit-specific opportunity cost shall be determined as follows: additional Condense Energy Use in excess of day-ahead Condense Energy Use multiplied by A plus [any applicable Condense Startup Cost due to additional Condense Startup Cost in real-time in excess of day-ahead Condense Startup Cost allocated to each Real-time Settlement Interval as described in PJM Manuals]. If the generation resource is operating as a synchronous condenser and also has a Real-time Synchronized Reserve assignment, resource's unit-specific opportunity cost in the Secondary Reserve Market shall be zero.

(iii) For each Real-time Settlement Interval, a total Market Revenue Neutrality Offset is calculated for each resource, if eligible. If there is a decrease in real-time reserve MW from a day-ahead market assignment in more than one market for that real-time settlement interval, the total Market Revenue Neutrality Offset is allocated to the Secondary Reserve market based on the ratio of the opportunity cost owed due to a reduction in assignment in real-time within the Secondary Reserve market and the total opportunity cost owed due to a reduction in assignment in real-time from all reserve markets, not to exceed the resource's opportunity cost owed in the Secondary Reserve market.

A resource is not eligible for Market Revenue Neutrality Offset for Secondary Reserve in a Real-time Settlement Interval for any of the following conditions:

(A) A resource's real-time Secondary Reserve assignment decreases due to the resource being self-scheduled to provide energy, Synchronized Reserve, or Regulation;

(B) A resource reduces flexibility in real-time such that the resource no longer qualifies to provide Secondary Reserve in real-time;

(C) A resource's Final Offer is less than its Committed Offer;

(D) A resource trips offline or otherwise becomes unavailable in real-time;

(E) A resource does not follow dispatch as described in section 3.2.3(o) above and section 3.2.3(o-1) above; or

(F) A resource that fails to come online and reach Economic Minimum output within 30 minutes as described in section 3.2.3A.01(h)(i) below.

(iv) A Secondary Reserve lost opportunity cost credit is determined for each resource for each Real-time Settlement Interval in accordance with the following equation:

(A + B) – (C + D + E + F)

Where:

A = day-ahead opportunity cost as determined in subsection (f)(i) above;

B = real-time opportunity cost as determined in subsection (f)(ii) above;

C = day-ahead clearing price credits as determined in subsection (b)(i) above;

D = real-time clearing price credits as determined subsection (b)(ii) above;

E = the applicable Market Revenue Neutrality Offset as determined in subsection (f)(iii) above; and

F = the opportunity cost credit owed due to a reduction in assignment in real-time as described in section 3.2.3A.01(f)(iii) above if not eligible for Market Revenue Neutrality Offset.

(v) The opportunity costs for Economic Load Response Participant resources and generation resources not synchronized to the grid shall be zero, except that Economic Load Response Participant resources may have a day-ahead opportunity cost, as determined in subsection (f)(i) above.

(g) For each operating hour, the sum of the Secondary Reserve lost opportunity cost credits credited in accordance with subsection (b)(iii) above shall be allocated and charged to each Market Participant that does not meet its hourly Secondary Reserve Obligation in proportion to its real-time purchases of Secondary Reserve in megawatt-hours during that hour.

(h) (i) In the event an offline generation resource has been assigned by the Office of the Interconnection to provide Secondary Reserve in real-time and is subsequently dispatched by the Office of the Interconnection to supply energy during that Operating Day and the resource qualifies as a Secondary Reserve resource at the time it is dispatched to provide energy, the Office of the Interconnection will assess the resource's performance as follows:

For each generation resource that fails to come online and reach Economic Minimum output within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval and for all prior intervals in which the resource was assigned to provide Secondary Reserve in the Real-time Secondary Reserve Market starting at the later of (A) the last interval the resource was online or (B) the beginning of that Operating Day and continuing up to the interval the resource failed to come online. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time not being paid for the assigned MW.

(ii) In the event an Economic Load Response Participant resource has been assigned by the Office of the Interconnection to provide Secondary Reserve in real-time and is subsequently dispatched to supply the Secondary Reserve assignment as a load reduction, the Office of the Interconnection will assess the resource's performance as follows:

For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between 29 and 31 minutes after the issuance of a dispatch instruction from the Office of the Interconnection.

For each Economic Load Response Participant resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described above, within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval, and for all prior intervals in which the resource was assigned to provide Secondary Reserve in the Real-time Secondary Reserve Market between such non-performance event starting at the later of (A) the last interval the resource reduced load at the instruction of the Office of the Interconnection or (B) the beginning of that Operating Day, and for all subsequent intervals through the earlier of (C) the next interval in which the resource is dispatched to reduce load or (D) the end of the Operating Day. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time, refunding all payments due for Secondary Reserve during such period.

(iii) For Batch Load Economic Load Response Participant Resources, a second method of verification will be used for instances where a Secondary Reserve assignment dispatched as an energy load reduction is initiated and the resource is operating at the minimum consumption level of its duty cycle. In this case, the magnitude of the response will be measured as the difference between (A) the minimum of the resource's consumption between the minute before and the minute after the end of the last settlement interval the resource reduced load at the instruction of the Office of the Interconnection and (B) the maximum consumption within a ten (10) minute period following the end of the last settlement interval the resource reduced load provided that all subsequent minutes following that minute are no less than 50% of the consumption in that minute.

For each Batch Load Economic Load Response Participant Resource that fails to reduce load by at least the Economic Minimum, where the measured response is the difference between the resource's starting MW usage and the resource's ending MW usage as described in section (ii) above or the difference between (A) and (B) as described in section (iii) above, within 30 minutes as instructed by the Office of the Interconnection, the resource's Real-time Secondary Reserve assignment will be set to zero megawatts for that interval, and for all prior intervals in which the resource was assigned to provide Secondary Reserve in either the Day-ahead or Real-time Secondary Reserve Markets between such non-performance event starting at the later of (A) the last interval the resource reduced load at the instruction of the Office of the Interconnection or (B) the beginning of that Operating Day, and for all subsequent intervals through the earlier of (C) the next interval in which the resource is dispatched to reduce load or (D) the end of the Operating Day. This results in the resource buying back the day-ahead assignment at the Real-time Secondary Reserve Market Clearing Price, or if solely assigned in real-time, refunding all payments due for Secondary Reserve during such period.

3.2.3A.02 Operating Reserve Demand Curves

The Office of the Interconnection shall establish Operating Reserve Demand Curves for clearing 30-minute Reserve, Primary Reserve, and Synchronized Reserve, for, as applicable, each Reserve Zone or Reserve Sub-zone to procure sufficient reserves to meet, as applicable, (a) 30-minute Reserve Requirement and Extended 30-minute Reserve Requirement; (b) Primary Reserve Requirement and Extended Primary Reserve Requirement; and (c) Synchronized Reserve Requirement and Extended Synchronized Reserve Requirement. The Operating Reserve Demand Curves established for each reserve type shall be used to commit such reserves in both the day-ahead and real-time reserve markets. The Operating Reserve Demand Curves shall be determined in accordance with the applicable Reserve Penalty Factors and PJM Manuals.

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output, when positive, of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from a steam-electric generating unit, a Hybrid Resource, or a combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3(c) hereof), and where the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C. An Energy Storage Resource Model Participant or a Hybrid Resource instructed to reduce charging to provide Reactive Services is not eligible for compensation under section (c).

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3(c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost for each Real-time Settlement Interval, limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(e) At the end of each Operating Day, where the active energy output (positive generation output) of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to section 3.2.3B(f). At the end of each Operating Day, when an Energy Storage Resource Model Participant or a Hybrid Resource is instructed to increase charging at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from a steam-electric generating unit, a Hybrid Resource, combined cycle unit, or a combustion turbine unit, where such unit is

pool scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3(c) hereof), and where the real time LMP revenues at the unit's bus are lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit in an amount equal to {(AG – TRLD MWh) x (UB - URTLMP)}where:

AG equals the actual output of the unit;

TRLD MWh equals the Tracking Ramp Limited Desired MWh determined according to Operating Agreement, Schedule 1, section 3.2.3(e-1);

UB equals the unit offer for that unit for which output, or charging, is increased, determined according to the lesser of the Final Offer or Committed Offer;

URTLMP equals the real time LMP at the unit's bus; and

where UB - URTLMP shall not be negative, except where applicable for an Energy Storage Resource Model Participant or a Hybrid Resource when instructed to increase charging.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Operating Agreement, Schedule 1, section 1.10.3(c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability or if an Energy Storage Resource Model Participant or a Hybrid Resource believes the above calculations in this section 3.2.3B do not accurately compensate the Market Participant for opportunity costs associated with following the Office of the Interconnection's dispatch instructions to modify a unit's charging or discharging for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate opportunity cost compensation, the Office of the Interconnection shall invoice the Market Participant accordingly. If the Market Monitoring Unit disagrees with the modified amount of

alternate opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in section 3.2.3A regarding provision of Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Synchronized Reserve Market Clearing Price for each Real-time Settlement Interval a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the product of the Condense Energy Use multiplied by the real time LMP at the generating unit's bus, (B) the generating unit's Condense Startup Cost, and (C) the unit-specific lost opportunity cost of the generating resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generating unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of the Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees in accordance with section 3.2.3(e-2). The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load ((a) net of operating

Behind The Meter Generation; and (b) excluding Direct Charging Energy) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the applicable Synchronized Reserve Requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in section 3.2.3A regarding provision of Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Real-time Synchronized Reserve Market Clearing Price for each applicable interval a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided

by the synchronous condenser or (ii) the sum of (A) the product of the Condense Energy Use multiplied by the real-time LMP at the generation bus of the generation resource, (B) the generation resource's Condense Startup Cost, and (C) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load ((a) net of operating Behind The Meter Generation; and (b) excluding Direct Charging Energy) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

Each Market Buyer shall be assessed Transmission Congestion Charges as specified in Operating Agreement, Schedule 1, section 5.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Operating Agreement, Schedule 1, section 5.

3.2.6 Emergency Energy.

(a) When the Office of the Interconnection has implemented Emergency procedures, resources offering Emergency energy are eligible to set real-time Locational Marginal Prices, capped at the energy offer cap plus the sum of the applicable Reserve Penalty Factors for the Synchronized Reserve Requirement and Primary Reserve Requirement, provided that the Emergency energy is needed to meet demand in the PJM Region.

(b) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each applicable interval of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(c) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each applicable interval of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(d) The net costs or net revenues associated with sales or purchases of energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each applicable interval of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Participant in accordance with the charges and credits specified in Operating Agreement, Schedule 1, sections 3.2.1 through 3.2.6, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Participant's internal accounting.

(b) If deliveries to a Market Participant that has PJM Interchange meters in accordance with Operating Agreement, section 14 include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market Participant, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market Participant and the unmetered Market Participant specified by them to the Office of the Interconnection.

3.3A Economic Load Response Participants.

3.3A.1 Compensation.

Economic Load Response Participants shall be compensated pursuant to sections 3.3A.5 and/or 3.3A.6 of this Schedule, for demand reduction offers submitted in the Day-Ahead Energy Market or Real-time Energy Market that satisfy the Net Benefits Test of section 3.3A.4; that are scheduled by the Office of the Interconnection; and that follow the dispatch instructions of the Office of the Interconnection. Qualifying demand reductions shall be measured by: 1) comparing actual metered load to an end-use customer's Customer Baseline Load or alternative CBL determined in accordance with the provisions of section 3.3A.2 or 3.3A.2.01, respectively; or 2) non-interval metered residential Direct Load Control customers, as metered on a current statistical sample of electric distribution company accounts, as described in the PJM Manuals or 3) by the MWs produced by on-Site Generators pursuant to the provisions of section 3.3A.2.02.

3.3A.2 Customer Baseline Load.

For Economic Load Response Participants that choose to measure demand reductions using an end-use customer's Customer Baseline Load ("CBL"), the CBL shall be determined using the following formula for such participant's Non-Variable Loads. Additionally, the following formula shall be used to determine a Peak Shaving Adjustment end-use customer's demand reductions when determining peak shaving performance rating as described in PJM Manual 19, unless an alternative CBL is approved pursuant to section 3.3A.2.01 of this schedule:

(a) The CBL for weekdays shall be the average of the highest 4 out of the 5 most recent load weekdays in the 45 calendar day period preceding the relevant load reduction event.

i. For the purposes of calculating the CBL for weekdays, weekdays shall not include:

1. NERC holidays;

2. Weekend days;

3. Event days. For the purposes of this section an event day shall be either:

(i) any weekday that an Economic Load Response Participant submits a settlement pursuant to section 3.3A.4 or 3.3A.5, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection; or

(ii) any weekday where the end-use customer location that is registered in the Economic Load Response program is also registered as a Demand Resource, and all end-use customer

locations on the relevant Economic Load Response registration have been dispatched by PJM during an emergency event.

4. Any weekday where the average daily event period usage is less than 25% of the average event period usage for the five days.

ii. If a 45-day period does not include 5 weekdays that meet the conditions in subsection (a)(i) of this section, provided there are 4 weekdays that meet the conditions in subsection (a)(i) of this section, the CBL shall be based on the average of those 4 weekdays. If there are not 4 eligible weekdays, the CBL shall be determined in accordance with subsection (iii) of this section.

iii. Section 3.3A.2(a)(i)(3) notwithstanding, if a 45-day period does not include 4 weekdays that meet the conditions in subsection (a)(i) of this section, event days will be used as necessary to meet the 4 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(b) The CBL for weekend days and NERC holidays shall be determined in accordance with the following provisions:

i. The CBL for Saturdays and Sundays/NERC holidays shall be the average of the highest 2 load days out of the 3 most recent Saturdays or Sundays/NERC holidays, respectively, in the 45 calendar day period preceding the relevant load reduction event, provided that the following days shall not be used to calculate a Saturday or Sunday/NERC holiday CBL:

1. Event days. For the purposes of this section an event day shall be either:

a. any Saturday and Sunday/NERC holiday that an Economic Load Response Participant submits a settlement pursuant to section 3.3A.5 or 3.3A.6, provided that Event Days shall exclude such days if the settlement is denied by the relevant LSE or electric distribution company or is disallowed by the Office of the Interconnection; or

b. any Saturday and Sunday/NERC holiday where the end-use customer that is registered in the Economic Load Response program is also registered as a Demand Resource, and all end-use customer locations on the relevant Economic Load Response registration have been dispatched by PJM during an emergency event.

2. Any Saturday or Sunday/NERC holiday where the average daily event period usage is less than 25% of the average event period usage level for the three days;

3. Any Saturday or Sunday/NERC holiday that corresponds to the beginning or end of daylight savings.

ii. If a 45-day period does not include 3 Saturdays or 3 Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, provided there are 2 Saturdays or Sundays/NERC holidays that meet the conditions in subsection (b)(i) of this section, the CBL will be based on the average of those 2 Saturdays or Sundays/NERC holidays. If there are not 2 eligible Saturdays or Sundays/NERC holidays, the CBL shall be determined in accordance with subsection (iii) of this section.

iii. Section 3.3A.2(b)(i)(1) notwithstanding, if a 45-day period does not include 2 Saturdays or Sundays/NERC holidays, respectively, that meet the conditions in subsection (b)(i) of this section, event days will be used as necessary to meet the 2 day requirement to calculate the CBL, provided that any such event days shall be the highest load event days within the relevant 45-day period.

(c) CBLs established pursuant to this section shall represent end-use customers' actual load patterns. If the Office of the Interconnection determines that a CBL or alternative CBL does not accurately represent a customer's actual load patterns, the CBL shall be revised accordingly pursuant to section 3.3A.2.01. Consistent with this requirement, if an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer upon whose behalf it is acting that would result in the adjustment of more than half the hours in the affected party's Customer Baseline Load by twenty percent or more for more than twenty days.

3.3A.2.01 Alternative Customer Baseline Methodologies.

(a) During the Economic Load Response Participant registration process pursuant to section 1.5A.3 of this Schedule, the relevant Economic Load Response Participant or the Office of the Interconnection ("Interested Parties") may, in the case of such participant's Non-Variable Load customers, and shall, in the case of its Variable Load customers, propose an alternative CBL calculation that more accurately reflects the relevant end-use customer's consumption pattern relative to the CBL determined pursuant to section 3.3A.2. During the Emergency and Pre-Emergency Load Response registration process pursuant to section 8.4 of this schedule, or as otherwise approved by the Office of the Interconnection, the relevant participant or the Office of the Interconnection may propose an alternative CBL calculation that more accurately reflects the relevant end-use customer's consumption pattern relative to the CBL determined pursuant to section 3.3A.2 of this schedule. In support of such proposal, the participant shall demonstrate that the alternative CBL method shall result in an hourly relative root mean square error of twenty percent or less compared to actual hourly values, as calculated in accordance with the technique specified in the PJM Manuals. Any proposal made pursuant to this section shall be provided to the other Interested Party.

(b) The Interested Parties shall have 30 days to agree on a proposal issued pursuant to subsection (a) of this section. The 30-day period shall start the day the proposal is provided to

the other Interested Party. If both Interested Parties agree on a proposal issued pursuant to this section, that alternative CBL calculation methodology shall be effective consistent with the date of the relevant Economic Load Response Participant registration.

(c) If agreement is not reached pursuant to subsection (b) of this section, the Office of the Interconnection shall determine a CBL methodology that shall result, as nearly as practicable, in an hourly relative root mean square error of twenty percent or less compared to actual hourly values within 20 days from the expiration of the 30-day period established by subsection (b). A CBL established by the Office of the Interconnection pursuant to this subsection (c) shall be binding upon both Interested Parties unless the Interested Parties reach agreement on an alternative CBL methodology prior to the expiration of the 20-day period established by this subsection (c).

(d) Operation of this section 3.3A.2.01 shall not delay Economic Load Response Participant registrations pursuant to Section 1.5A.3, provided that the alternative CBL established pursuant to this section shall be used for all related energy settlements made pursuant to sections 3.3A.5 and 3.3A.6.

(e) The Office of the Interconnection shall periodically publish alternative CBL methodologies established pursuant to this section in the PJM Manuals.

(f) Emergency and Pre-Emergency Load Response registrations will use the CBL defined on the associated economic registration for measuring demand reductions when determining the participant's compliance with its capacity obligations pursuant to Schedule 6 of the RAA, unless it is the maximum baseload CBL as defined in the PJM Manuals, in which case the participant will use the CBL set forth in the Emergency or Pre-Emergency Load Response registration.

3.3A.2.02 On-Site Generators.

On-Site Generators used as the basis for Economic Load Response Participant status pursuant to Tariff, Attachment K-Appendix, section 1.5A shall be subject to the following provisions:

i. The On-Site Generator shall be used solely to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market and shall not otherwise have been operating;

ii. If subsection (i) does not apply, the amount of energy from an On-Site Generator used to enable an Economic Load Response Participant to provide demand reductions in response to the Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market shall be capable of being quantified in a manner that is acceptable to the Office of the Interconnection.

3.3A.3 Symmetric Additive Adjustment.

(a) Customer Baseline Levels established pursuant to section 3.3A.2 shall be adjusted by the Symmetric Additive Adjustment. Unless an alternative formula is approved by the Office of the Interconnection, the Symmetric Additive Adjustment shall be calculated using the following formula:

Step 1: Calculate the average usage over the 3 hour period ending 1 hour prior to the start of event.

Step 2: Calculate the average usage over the 3 hour period in the CBL that corresponds to the 3 hour period described in Step 1.

Step 3: Subtract the results of Step 2 from the results of Step 1 to determine the symmetric additive adjustment (this may be positive or negative).

Step 4: Add the symmetric additive adjustment (i.e. the results of Step 3) to each hour in the CBL that corresponds to each event hour.

(b) Following a Load Reduction Event that is submitted to the Office of the Interconnection for compensation, the Office of the Interconnection shall provide the Notification window(s), if applicable, directly metered data and Customer Baseline Load and Symmetric Additive Adjustment calculation to the appropriate electric distribution company for optional review. The electric distribution company will have ten Business Days to provide the Office of the Interconnection with notification of any issues related to the metered data or calculations.

3.3A.4 Net Benefits Test.

The Office of the Interconnection shall identify each month the price on a supply curve, representative of conditions expected for that month, at which the benefit of load reductions provided by Economic Load Response Participants exceed the costs of those reductions to other loads. In formulaic terms, the net benefit is deemed to be realized at the price point on the supply curve where (Delta LMP x MWh consumed) > (LMP_{NEW} x DR), where LMP_{NEW} is the market clearing price after Economic Load Response is dispatched and Delta LMP is the price before Economic Load Response is dispatched minus the LMP_{NEW}).

The Office of the Interconnection shall update and post the Net Benefits Test results and analysis for a calendar month no later than the 15th day of the preceding calendar month. As more fully specified in the PJM Manuals, the Office of the Interconnection shall calculate the net benefit price level in accordance with the following steps:

Step 1. Retrieve generation offers from the same calendar month (of the prior calendar year) for which the calculation is being performed, employing market-based price offers to the extent available, and cost-based offers to the extent market-based price offers are not available. To the extent that generation offers are unavailable from historical data due to the addition of a Zone to the PJM Region the Office of the Interconnection shall use the most recent generation offers that

best correspond to the characteristics of the calendar month for which the calculation is being performed, provided that at least 30 days of such data is available. If less than 30 days of data is available for a resource or group of resources, such resource[s] shall not be considered in the Net Benefits Test calculation.

Step 2: Adjust a portion of each prior-year offer representing the typical share of fuel costs in energy offers in the PJM Region, as specified in the PJM Manuals, for changes in fuel prices based on the ratio of the reference month spot price to the study month forward price. For such purpose, natural gas shall be priced at the Henry Hub price, number 2 fuel oil shall be priced at the New York Harbor price, and coal shall be priced as a blend of coal prices representative of the types of coal typically utilized in the PJM Region.

Step 3. Combine the offers to create daily supply curves for each day in the period.

Step 4. Average the daily curves for each day in the month to form an average supply curve for the study month.

Step 5. Use a non-linear least squares estimation technique to determine an equation that reasonably approximates and smooths the average supply curve.

Step 6. Determine the net benefit level as the point at which the price elasticity of supply is equal to 1 for the estimated supply curve equation established in Step 5.

3.3A.5 Market Settlements in Real-time Energy Market.

(a) Economic Load Response Participants that submit offers for load reductions in the Day-ahead Energy Market by no later than 2:15 p.m. on the day prior to the Operating Day that cleared or that otherwise are dispatched by the Office of the Interconnection for the Operating Day shall be compensated for reducing demand based on the actual kWh relief provided in excess of committed day-ahead load reductions. The offer shall contain the Offer Data specified in Tariff, Attachment K-Appendix, section 1.10.1A(k) and shall not thereafter be subject to change; provided, however, the Economic Load Response Participant may update the previously specified minimum or maximum load reduction quantity and associated price by submitting a Real-time Offer for a clock hour by providing notice to the Office of the Interconnection in the form and manner specified in the PJM Manuals no later than 65 minutes prior to such clock hour. Economic Load Response Participants may also submit Real-time Offers for a clock hour for an Operating Day containing Offer Data specified in Tariff, Attachment K-Appendix, section 1.10.1A(k), and may update such offers up to 65 minutes prior to such clock hour. Economic Load Response Participants may, at their option, combine separately registered loads that have a common pricing point into a single portfolio for purposes of offering and dispatching their load reduction capability; provided however that any load reductions will continue to be measured and verified at the individual registration level prior to aggregation at the portfolio level for purposes of energy market and balancing energy uplift settlements. An Economic Load Response Participant that curtails or causes the curtailment of demand in real-time in response to PJM dispatch, and for which the applicable real-time LMP is

equal to or greater than the threshold price established under the Net Benefits Test, will be compensated by PJMSettlement at the real-time Locational Marginal Price.

(b) In cases where the demand reduction follows dispatch, as defined in Tariff, Attachment K-Appendix, section 3.2.3(o-1), as instructed by the Office of the Interconnection, and the demand reduction offer price is equal to or greater than the threshold price established under the Net Benefits Test, payment will not be less than the total value of the demand reduction bid. For the purposes of this subsection, the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing demand, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the demand reduction must be committed.

Any shortfall between the applicable Locational Marginal Price and the total value of the demand reduction bid will be made up through normal, balancing Energy Make Whole credits. In all cases under this subsection, the applicable zonal or aggregate (including nodal) Locational Marginal Price shall be used as appropriate for the individual end-use customer. The foregoing notwithstanding, when calculating balancing Energy Make Whole credits for Economic Load Response Participants pursuant to Tariff, Attachment K-Appendix, section 3.2.3, the second Segment shall exclude shutdown costs.

(c) For purposes of load reductions qualifying for compensation hereunder, an Economic Load Response Participant shall accumulate credits for energy reductions in those hours when the energy delivered to the end-use customer is less than the end-use customer's Customer Baseline Load at the applicable Locational Marginal Price for the Real-time Settlement Interval. In the event that the end-use customer's hourly energy consumption is greater than the Customer Baseline Load, the Economic Load Response Participant will accumulate debits at the applicable Locational Marginal Price for the Real-time Settlement Interval for the amount the end-use customer's hourly energy consumption is greater than the Customer Baseline Load. If the actual load reduction, compared to the desired load reduction is outside the deviation levels specified in Tariff, Attachment K-Appendix, section 3.2.3(o-1), the Economic Load Response Participant shall be assessed balancing uplift charges equal to the Economic Load Response Participant's daily total of hourly deviations in each region times the regional adder rate for deviations in the relevant region plus the daily total of hourly deviations in the RTO region times the RTO region balancing uplift rate for deviations in accordance with Tariff, Attachment K-Appendix, section 3.2.3. The rates used for Economic Load Response Participant's balancing uplift charges are calculated in accordance with Tariff, Attachment K-Appendix, section 3.2.3(q-1), however the credits used in the calculation of the rates exclude balancing Energy Make Whole credits paid to Economic Load Response Participants. Market Participants with deviations in the RTO region, excluding Economic Load Response Participant deviations, shall be allocated any uplift credit associated with the collection of these charges.

(d) The cost of payments to Economic Load Response Participants under this section (excluding any portion of the payments recovered as balancing Energy Marke Whole credits pursuant to subsection (b) of this section) for load reductions that are compensated at the applicable full LMP, in any Zone for any hour, shall be recovered from Market Participants on a ratio-share basis based on their real-time exports from the PJM Region and from Load Serving

Entities on a ratio-share basis based on their real-time loads in each Zone for which the load-weighted average Locational Marginal Price for the hour during which such load reduction occurred is greater than or equal to the price determined under the Net Benefits Test for that month, with the ratio shares determined as follows:

The ratio share for LSE **i** in zone **z** shall be $\mathbf{RTL_{iz}/(RTL + X)}$
and the ratio share for party **j** shall be $\mathbf{X_j/(RTL + X)}$.

Where:

RTL is the total real time load in all zones where LMP ≥ Net Benefits Test price;
$\mathbf{RTL_{iz}}$ is the real-time load for LSE **i** in zone **z**;
X is the total export quantity from PJM in that hour; and
$\mathbf{X_j}$ is the export quantity by party **j** from PJM.

3.3A.6 Market Settlements in the Day-ahead Energy Market.

(a) Economic Load Response Participants dispatched as a result of a qualifying demand reduction offer in the Day-ahead Energy Market shall be compensated for reducing demand based on the reductions of kWh committed in the Day-ahead Energy Market. An Economic Load Response Participant that submits a demand reduction bid day ahead that is accepted by the Office of the Interconnection and for which the applicable day ahead LMP is greater than or equal to the Net Benefits Test shall be compensated by PJMSettlement at the day-ahead Locational Marginal Price.

Economic Load Response Participants may, at their option, combine separately registered loads that have a common pricing point into a single portfolio for purposes of offering and dispatching their load reduction capability; provided however that any load reductions will continue to be measured and verified at the individual registration level prior to aggregation at the portfolio level for purposes of energy market and balancing uplift settlements.

(b) Total payments to Economic Load Response Participants for accepted day-ahead demand reduction bids with an offer price equal to or greater than the threshold price established under the Net Benefits Test that follow the dispatch instructions of the Office of the Interconnection will not be less than the total value of the demand reduction bid. For the purposes of this subsection, the total value of a demand reduction bid shall include any submitted start-up costs associated with reducing load, including direct labor and equipment costs and opportunity costs and any costs associated with a minimum number of contiguous hours for which the load reduction must be committed. Any shortfall between the applicable Locational Marginal Price and the total value of the demand reduction bid will be made up through normal, day-ahead Energy Make Whole credits. In all cases under this subsection, the applicable zonal or aggregate (including nodal) Locational Marginal Price shall be used as appropriate for the individual end-use customer.

(c) Economic Load Response Participants that have demand reductions committed in the Day-ahead Energy Market that deviate from the day-ahead schedule in real time shall be

charged or credited for such variance at the real time LMP plus or minus an amount equal to the applicable balancing uplift charge in accordance with Tariff, Attachment K-Appendix, section 3.2.3. Load Serving Entities that otherwise would have load that was reduced shall receive any associated uplift credit.

(d) The cost of payments to Economic Load Response Participants for accepted day-ahead demand reduction bids that are compensated at the applicable full, day ahead LMP under this section (excluding any portion of the payments recovered as day-ahead Energy Make Whole credits pursuant to subsection (b) of this section) for load reductions in any Zone for any hour shall be recovered from Market Participants on a ratio-share basis based on their real-time exports from the PJM Region and from Load Serving Entities on a ratio-share basis based on their real-time loads in each Zone for which the load-weighted average real-time Locational Marginal Price for the hour during which such load reduction occurred is greater than or equal to the price determined under the Net Benefits Test for that month, in accordance with the formula prescribed in Tariff, Attachment K-Appendix, section 3.3A.5(d).

3.3A.7 Prohibited Economic Load Response Participant Market Settlements.

(a) Settlements pursuant to sections 3.3A.5 and 3.3A.6 shall be limited to demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market that satisfy the Net Benefits Test and are dispatched by the Office of the Interconnection.

(b) Demand reductions that do not meet the requirements of section 3.3A.7(a) shall not be eligible for settlement pursuant to sections 3.3A.5 and 3.3A.6. Examples of settlements prohibited pursuant to this section 3.3A.7(b) include, but are not limited to, the following:

i. Settlements based on variable demand where the timing of the demand reduction supporting the settlement did not change in direct response to Locational Marginal Prices in the Real-time Energy Market and/or the Day-ahead Energy Market;

ii. Consecutive daily settlements that are the result of a change in normal demand patterns that are submitted to maintain a CBL that no longer reflects the relevant end-use customer's demand;

iii. Settlements based on on-site generation data if the On-Site Generator is not supporting demand reductions executed in response to the Locational Marginal Price in the Real-time Energy Market and/or the Day-ahead Energy Market;

iv. Settlements based on demand reductions that are the result of operational changes between multiple end-use customer sites in the PJM footprint;

v. Settlements that do not include all hours that the Office of the Interconnection dispatched the load reduction, or for which the load reduction cleared in the Day-ahead Market.

(c) The Office of the Interconnection shall disallow settlements for demand reductions that do not meet the requirements of section 3.3A.7(a). If the Economic Load Response Participant continues to submit settlements for demand reductions that do not meet the requirements of section 3.3A.7(a), then the Office of the Interconnection shall suspend the Economic Load Response Participant's PJM Interchange Energy Market activity and refer the matter to the FERC Office of Enforcement.

3.3A.8 Economic Load Response Participant Review Process.

(a) The Office of the Interconnection shall review the participation of an Economic Load Response Participant in the PJM Interchange Energy Market under the following circumstances:

i. An Economic Load Response Participant's registrations submitted pursuant to Tariff, Attachment K-Appendix, section 1.5A.3 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).

ii. An Economic Load Response Participant's settlements pursuant to sections 3.3A.5 and 3.3A.6 are disputed more than 10% of the time by any relevant electric distribution company(ies) or Load Serving Entity(ies).

iii. An Economic Load Response Participant's settlements pursuant to sections 3.3A.5 and 3.3A.6 are denied by the Office of the Interconnection more than 10% of the time.

iv. An Economic Load Response Participant's registration will be reviewed when settlements are frequently submitted or if its actual loads frequently deviate from the previously scheduled quantities (as determined for purposes of assessing balancing uplift charges). PJM will notify the Participant when their registration is under review. While the Participant's registration is under review by PJM, the Participant may continue economic load reductions but all settlements will be denied by PJM until the registration review is resolved pursuant to subsection (i) or (ii) below. PJM will require the Participant to provide information within 30 days to support that the settlements were submitted for load reduction activity done in response to price and not submitted based on the end-use customer's normal operations.

i) If the Participant is unable to provide adequate supporting information to substantiate the load reductions submitted for settlement, PJM will terminate the registration and may refer the Participant to either the Market Monitoring Unit or the Federal Energy Regulatory Commission for further investigation.

ii) If the Participant does provide adequate supporting information, the settlements denied by PJM will be resubmitted by the Participant for review according to existing PJM market rules. Further, PJM may introduce an alternative Customer Baseline Load if the existing Customer

Baseline Load does not adequately reflect what the customer load would have been absent a load reduction.

v. The electric distribution company may only deny settlements during the normal settlement review process for inaccurate data including, but not limited to: meter data, line loss factor, Customer Baseline Load calculation, interval meter owner and a known recurring end-use customer outage or holiday.

(b) The Office of the Interconnection shall have thirty days to conduct a review pursuant to this section 3.3A.8. The Office of the Interconnection may refer the matter to the PJM MMU and/or the FERC Office of Enforcement if the review indicates the relevant Economic Load Response Participant and/or relevant electric distribution company or LSE is engaging in activity that is inconsistent with the PJM Interchange Energy Market rules governing Economic Load Response Participants.

8.8 Market Settlements

Payment for reducing load is based on the actual kWh relief provided plus the adjustment for losses, subject to the Reporting and Compliance provisions below. The magnitude of capacity relief provided by Full Program Option participants shall be the amount determined in accordance with the Reporting and Compliance provisions below. The magnitude of relief provided by Energy Only Option participants, and the magnitude of energy relief provided by Full Program Option participants, may be less than, equal to, or greater than the kW amount declared on the Emergency or Pre-Emergency registration. Compensation will be provided for reductions in energy consumption during emergency events, tests and associated retest(s), where applicable by Full Program Option participants and Energy Only Option participants regardless of whether the participant's load during the event exceeds its peak load contribution for the applicable Delivery Year.

PJMSettlement pays the applicable LMP to the PJM Member that nominates the load. Payment will be equal to the measured energy load reduction adjusted for losses times the applicable LMP. The measured energy load reduction for locations with approved Economic Load Response registrations prior to a Load Management Event that have an economic CBL different than the maximum base load as defined in the PJM Manuals will use the associated economic CBL to determine the energy load reduction unless the locations on the Emergency Load Response registration are not the same locations as those included on the Economic Load Response registration. If, at the time that a Load Management Event or emergency event is initiated by PJM, an end-use customer is already responding economically (i.e., pursuant to the Economic Load Response rules) and economic CBL is based on Symmetric Additive Adjustment, then the CBL calculated based on the Symmetric Additive Adjustment period prior to the economic event will be used. Locations that do not have an approved Economic Load Response registration prior to a Load Management Event will use the Customer Baseline Load as defined in section 3.3A.2 and associated Symmetric Additive Adjustment as defined in section 3.3A.2.01 of this schedule unless an alternative CBL is approved pursuant to section 3.3A.2.01 of this schedule as the CBL to determine the energy load reduction.

If, however, the sum of the hourly energy payments to a Curtailment Service Provider with a Demand Resource Registration dispatched by PJM for actual, achieved reductions for an emergency event is not greater than or equal to the offer value (i.e. Minimum Dispatch Price and shut down costs) then the Curtailment Service Provider will be made whole up to the offer value for its actual, achieved reductions for the Demand Resource Registration.

Locations on Economic Load Response registrations dispatched in the Real-time Energy Market or cleared in the Day-ahead Energy Market that are also included on an Emergency Load Response and Pre-Emergency Load Response registration as Full Program Option, and that have also been dispatched as part of an emergency event for the same hour (i.e., have an "overlapping dispatch hour") will be compensated for energy based on emergency energy settlement and cost allocation rules as set forth in this section and in the PJM Manuals. Overlapping dispatch hours will use shutdown costs based on what was considered for the economic event, and no balancing uplift charges will be assessed for deviations from real-time dispatch amounts or from cleared day-ahead commitments. To avoid duplicative energy payments, overlapping dispatch hours for

an aggregate registration (i.e., multiple locations on the same registration) or dispatch groups where locations on the Emergency Load Response and Pre-Emergency Load Response registration are not the same locations as those on the Economic Load Response registration will have hourly economic energy load reduction and/or hourly emergency energy load reduction prorated based on load reduction capability provided by the Curtailment Service Provider for the locations.

The Curtailment Service Provider will only submit energy settlements for Load Management Events that occur outside of the specific availability period defined in the Reliability Assurance Agreement for each Demand Resource type if the Curtailment Service Provider has confirmed that the customers on the registration did take action to reduce load or the registration reflects the entire group of mass market customers for which an energy settlement will either be submitted for all or none of the mass market customers, as approved by PJM. The Curtailment Service Provider will only submit energy settlements for tests and for each registration for Load Management Events that occur during the product specific availability period as defined for each product in the Reliability Assurance Agreement if the Curtailment Service Provider also provides associated load data for each registration in order to calculate that registration's capacity compliance.

Full Program Option participants that fail to provide a load reduction (as measured as set forth in the Reporting and Compliance provisions below) when dispatched by PJM shall be assessed penalties and/or charges as specified in Tariff, Attachment DD and the Reliability Assurance Agreement, as applicable.

During emergency conditions, costs for emergency purchases in excess of LMP are allocated among PJM Market Buyers in proportion to their increase in net purchases minus real-time dispatch reduction megawatts from the PJM energy market during the hour in the Real-time Energy Market compared to the Day-ahead Energy Market. Consistent with this pricing methodology, all charges under the Emergency Load Response and Pre-Emergency Load Response Program are allocated to purchasers of energy, in proportion to their increase in net purchases minus real-time dispatch reduction megawatts from the PJM energy market during the hour from day-ahead to real-time.

The cost of payments for Emergency Load Response and Pre-Emergency Load Response energy settlements for tests, shall be recovered from Market Participants on a ratio-share basis based on their real-time exports from the PJM Region and from Load Serving Entities on ratio-share basis based on their real-time loads in each Zone for that month where the tests were conducted, with the ratio shares determined as follows:

The ratio share for LSE i in zone z shall be RTLiz/(RTL + X)
and the ratio share for party j shall be Xj/(RTL + X).
Where:

RTL is the total real time load in all zones where Load Management was tested;
RTLiz is the real-time load for LSE i in zone z;
X is the total export quantity from PJM in that hour; and

Xj is the export quantity by party j from PJM.

Emergency Load Response and Pre-Emergency Load Response Program charges and credits will appear on the PJM Members monthly bill, as described in the ***PJM Manual for Operating Agreement Accounting*** and the ***PJM Manual for Billing***.