955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

Jacqulynn Hugee
Assistant General Counsel - Markets
Telephone 610.666.8208 | Facsimile 610.666.8211
hugeej@pjm.com

December 19, 2011

Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426-0001

Re: PJM Interconnection, L.L.C., Docket No. ER12-636 -000

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act, 16 U.S.C. § 824d (2000), and the Commission's Regulations, 18 C.F.R. Part 35 (2007), PJM Interconnection, L.L.C. ("PJM") hereby submits for filing numerous non-substantive, clerical, ministerial and substantive revisions to correct, clarify and/or make consistent certain provisions of the PJM Open Access Transmission Tariff ("Tariff"), Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement") and Reliability Assurance Agreement Among Load Serving Entities in the PJM Region ("RAA"). Further, pursuant to Rule 207 of the Commission's Rules of Practice and Procedure, 18 C.F.R. §§ 385.207, PJM also respectfully requests a limited waiver as may be necessary to excuse PJM's failure to fully comply with the provisions of Section 3.2.3A(e) and (f) of Schedule 1 of the Operating Agreement and the identical, parallel provisions of Attachment K-Appendix of the Tariff with respect to the calculation of the Synchronized Reserve Market Clearing Price and the credit due to a Generating Market Buyer providing Tier 2 Synch Reserves for the reasons more fully explained herein.[1]

[1] The referenced provisions are identical and are in both Schedule 1 of the Operating Agreement and Attachment K – Appendix of the Tariff. All further references in this transmittal letter to Sections 1.10.8 and 3.2.3A shall only be made to the Operating Agreement provisions, without reference to the parallel

PJM requests that the Commission issue its order accepting the enclosed revisions by no later than February 17, 2012, sixty (60) days from the date of this filing, with an effective date of February 18, 2012 for all revisions.

I. Procedural Background and Stakeholder Process

In March 2010, PJM commenced a major undertaking to review its Commission-approved governing documents, including the Tariff, Operating Agreement and RAA, to assess PJM's operational quality with the referenced documents to determine whether PJM is adhering to all of its requirements as set forth therein (the "Quality Project"). The benefits that were intended to be realized as a result of the Quality Project included the assignment of "ownership" of the various requirements to the extent necessary, verification of operational quality, and clarification of regulatory requirement uncertainties.

In the initial phase of the Quality Project, PJM identified over 4,600 PJM requirements in the Commission-approved governing documents that were reviewed. PJM staff painstakingly reviewed each such requirement to determine their priority, and to determine whether (a) PJM was complying with such requirements, (b) the provisions of the PJM Manuals were consistent with the requirements in the governing agreements, (c) revisions, corrections or clarifications should be made to make the governing documents to address the particular requirement, and (d) PJM needed to implement any new processes or improve existing processes to effectuate particular requirements or ensure compliance. The initiative has resulted in PJM managing risk

Tariff provisions. Capitalized terms used and not otherwise defined herein have the meaning set forth in the Operating Agreement, Tariff and RAA.

by establishing a methodology to create documented, well-controlled, sustainable processes to ensure a continued level of quality following employee turnover, new roles, regulatory document revisions, and other changes. PJM staff concluded that a relatively small number of the over 4,600 requirements reviewed require revisions to be made or processes to be implemented, some of which are the subject of this filing.

In addition, while in the process of conducting this Quality Project review, PJM staff identified a small number of additional revisions that should be made to the governing agreements to clarify certain sections, delete obsolete language and correct other provisions.

For ease of review, PJM provides herewith an extensive chart, attached hereto as Attachment A, which describes each proposed revision. The "PJM Section Title" column of the chart is color-coded to reflect whether the proposed revision emanated from the Quality Project review (black font) or whether it is a revision that was identified by PJM staff to clarify or correct certain typographical errors, clerical errors and delete obsolete provisions, i.e. "Non-Quality Project" (red font). Additionally, PJM also submits several minor revisions to clarify the titles of various sections in the electronic tariff software by submitting non-substantive revisions to the metadata in the Section Title and Section Description to ensure that the sections are labeled properly.

To assist PJM stakeholders in their review and consideration of the various revisions, PJM made several presentations and conducted conference calls to provide stakeholders with as much information as they desired to receive about each proposed change. PJM originally posted its proposed revisions reflected in the chart that is attached hereto as Attachment A for the Markets Implementation Committee ("MIC") for

informational purposes for its August 9, 2011 meeting,[2] then presented the revisions for informational purposes and discussion to the Markets and Reliability Committee ("MRC") on August 17, 2011[3] and September 15, 2011,[4] and to the PJM Members Committee ("MC") on August 25, 2011.[5] Given stakeholders' desire to discuss the rationale for making a select number of the proposed revisions in further detail, PJM held two conference calls on October 3 and 4, 2011 for the sole purpose of providing additional information and explanation regarding these revisions.[6]

All of the proposed revisions reflected in the chart that is attached hereto as Attachment A, except the revision to Section 1.10.8(c) of Schedule 1 of the Operating Agreement which was withdrawn from consideration for further discussion, were endorsed by the MRC by acclamation at its October 12, 2011 meeting, with one abstention and no objections,[7] and were approved/endorsed at the October 20, 2011

[2] *See* PJM's proposed revisions posted on PJM's Web site at http://www.pjm.com/~/media/committees-groups/committees/mic/20110809/20110809-item-13e-proposed-markets-revisions-clean-up-correction.ashx.

[3] *See* PJM's proposed revisions posted on its Web site at http://www.pjm.com/~/media/committees-groups/committees/mrc/20110817/20110817-item-07-proposed-oa-oatt-raa-revisions.ashx.

[4] *See* PJM's proposed revisions posted on its Web site at http://www.pjm.com/~/media/committees-groups/committees/mrc/20110915/20110915-item-03-quality-project-oa-tariff-raa-proposed-revisions.ashx.

[5] *See* PJM's proposed revisions posted for the 8/25/2011 MC meeting on its Web site at http://www.pjm.com/~/media/committees-groups/committees/mc/20110825/20110825-item-06-chart-proposed-markets-revisions-clean-up-correction.ashx.

[6] *See* PJM's proposed revisions discussed during the MRC conference call on its Web site at http://www.pjm.com/~/media/committees-groups/committees/mrc/20111003/20111003-chart-proposed-markets-revisions-clean-up-correction.ashx.

[7] *See* Minutes of MRC Meeting of October 12, 2011 posted on PJM's Web site at http://www.pjm.com/~/media/committees-groups/committees/mrc/20111116/20111116-draft-minutes-mrc-20111012.ashx.

MC meeting by acclamation with no objections or abstentions.[8] Thereafter, the proposed revision to Section 1.10.8(c) of Schedule 1 of the Operating Agreement was endorsed by the MRC at its November 16, 2011 MRC meeting by acclamation with no objections and one abstention,[9] and endorsed/approved by the MC at its November 22, 2011 meeting by acclamation with no objections and five abstentions.

As required by Section 16.4 of the RAA, the PJM Board of Managers approved the revisions to the RAA at its meeting held on December 6, 2011.

II. Proposed Revisions

The chart appended hereto as Attachment A describes revisions to the Tariff, Operating Agreement and RAA which were approved/endorsed by PJM stakeholders and represent ministerial formatting errors to properly reflect defined terms, corrections to properly reflect revisions that have already been accepted by the Commission in prior filings, revisions to accurately reflect PJM's processes, procedures and calculations, deletions of obsolete references and provisions, and clarifications of ambiguous provisions, among others. The chart contains detailed explanations for why each respective revision is proposed, in addition to the PJM Section Title, Record ID, proposed effective date, Version, Priority Code and Technology Revision to assist the Commission with its review of the proposed changes.

[8] *See* Minutes of MC Meeting of October 20, 2011 posted on PJM's Web site at http://www.pjm.com/~/media/committees-groups/committees/mc/20111122/20111122-draft-minutes-mc-20111020.ashx.

[9] *See* Minutes of MRC Meeting of November 16, 2011 posted on its Web site at http://www.pjm.com/~/media/committees-groups/committees/mrc/20111116/20111116-draft-minutes-mrc.ashx.

This filing is the first of several filings that PJM expects to submit as a result of the Quality Project initiative. In fact, there is another set of proposed non-substantive and ministerial revisions emanating from the Quality Project that is currently being discussed in the PJM stakeholder process.

III. Waiver

With respect to the proposed revision to Section 3.2.3A(e) and (f) of Schedule 1 of the Operating Agreement being submitted with this filing, PJM requests that the Commission grant a limited waiver of Section 3.2.3A(e) and (f) to the extent necessary to excuse its past, current and future failures to calculate Synchronized Reserve Market Clearing Price and the credit due to a Generating Market Buyer providing Tier 2 Synch Reserves strictly according to the current, incorrect wording of Section 3.2.3A(e) and (f) of Schedule 1 of the Operating Agreement, and to allow that waiver to remain in effect until such time as the Commission accepts the proposed revision thereto to correct the language to accurately reflect the manner in which the calculation should properly be conducted. PJM believes that good cause exists for the requested limited waiver and that granting the requested waiver to PJM is the only equitable approach possible under the circumstances because a strict application of the provisions would lead to an inequitable, unjust and unreasonable result.

To address these types of issues, the Commission has granted waivers of tariff requirements to alleviate the effects of an error where: (1) an underlying error was made in good faith; (2) the waiver was of limited scope; (3) a concrete problem needed to be remedied; and (4) the waiver did not have undesirable consequences, such as harming

third parties.[10] All of these factors dictate in favor of granting PJM's limited waiver request.

A. Good Faith

Presently Section 3.2.3A(e) and (f) provides that:

> (e) In determining the Synchronized Reserve Market Clearing Price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the expected Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) ***the absolute value of*** the difference between the expected 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 Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. The opportunity costs for a Demand Resource shall be zero.
>
> (f) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve

[10] *See, e.g.*, *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,069 at P 8 (2011) ("*PJM*"); *ISO New England Inc.*, 134 FERC ¶ 61,182 at P 8 (2011) ("*ISO-NE*"); *California Indep. Sys. Operator, Inc.*, 132 FERC ¶ 61,004 at P 10 (2010) ("*CAISO*"); *Hudson Transmission Partners, LLC*, 131 FERC ¶ 61,157 at P 10 (2010) ("*HTP*"); *Pittsfield Generating Co., L.P.*, 130 FERC ¶ 61,182 at P 9-10 (2010) ("*Pittsfield*"); *ISO New England Inc. - EnerNOC*, 122 FERC ¶ 61,297 (2008) ("*EnerNOC*"); *Central Vermont Public Service Corp.*, 121 FERC ¶61,225 (2007) ("*Central Vermont*"); *Waterbury Generation LLC*, 120 FERC ¶ 61,007 (2007) ("*Waterbury*"); *Acushnet Co.*, 122 FERC ¶ 61,045 (2008) ("*Acushnet*").

> offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to 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, times (B) ***the absolute value of*** 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 Synchronized Reserve set point for the generation resource) in the PJM Interchange Energy Market. The opportunity costs for a Demand Resource shall be zero. (emphasis added)

However, in determining the appropriate amount of the Synchronized Reserve Market Clearing Price and the credit due to a Generating Market Buyer providing Tier 2 Synch Reserves, PJM doesn't calculate the real-time opportunity costs by multiplying the reduction in Tier 2 cleared MW by the *absolute value* of the difference between LMP at the generation bus and the offer price for energy from the generation resource as Section 3.2.3A dictates. Rather, PJM calculates the real-time opportunity costs by multiplying the reduction in Tier 2 cleared MW by the *positive difference* between LMP and the offer price. Using the positive difference rather than the absolute value is the correct way to perform the calculation as further discussed below.

It was during its Quality Project review that PJM discovered the error in the language describing the calculation of Synchronized Reserve Market Clearing Price and the credit due to a Generating Market Buyer providing Tier 2 Synch Reserves. In reviewing the history of Section 3.2.3A, PJM determined that the absolute value language was incorrectly inserted into that section when it was originally incorporated into the Operating Agreement in a filing made by PJM on March 20, 2003 in Docket No.

RT01-2-006. Apparently, the language was incorrectly copied and carried over from the provision in Section 3.2.2(d) and (e) concerning the calculation of the Regulation Market Clearing Price.

Absolute value is defined as: "The numerical value of a real number without regard to its sign. For example, the absolute value of -4 (written $|-4|$) is 4."[11] In other words, "the absolute value of a number is the distance the number is from zero."[12] Using absolute value is correct with respect to calculating the Regulation Market Clearing Price because generators may have their output raised or lowered from a point that would otherwise be economic to provide Regulation. This means that the opportunity cost for providing Regulation as opposed to providing energy may take the form of either, lost revenue in the energy market because the generation resource had to reduce its output below where it was economic (LMP > offer price), or, increased costs when the unit has to raise its output to a point where its cost to operate at that output level is higher than the LMP (offer > LMP). Because the Regulation opportunity cost may be incurred by either raising or lowering the unit's output from its ideal, economic point, the absolute value is appropriate in this case.

On the other hand, unlike the calculation Regulation Market Clearing Price, the calculation of Synchronized Reserve Market Clearing Price and the credit due to a Generating Market Buyer providing Tier 2 Synch Reserves should not be based on the absolute value of the difference between LMP and offer price because PJM does not dispatch generators to higher output level for the purpose of providing reserves like it

[11] http://www.thefreedictionary.com/absolute+value.

[12] http://www.basic-mathematics.com/definition-of-absolute-value.html.

does for Regulation. Moreover, it is inappropriate to calculate the Synchronized Reserve Market Clearing Price and the credit due to a Generating Market Buyer providing Tier 2 Synch Reserves using the absolute value in the calculation, because if LMP was less than the cost at the minimum MW amount of electric energy that a generating resource produces while under economic dispatch, the resource would not incur an opportunity cost by providing reserves because operating at its minimum output point would be economic.

PJM explained to it stakeholders that the underlying error in Section 3.2.3A(e) and (f) is related to an implementation flaw when the referenced calculation was originally incorporated into the Operating Agreement. PJM's stakeholders understood PJM's explanation and the need for the proposed revision to the Operating Agreement. Accordingly, they overwhelmingly approved PJM's proposal filed herewith to revise Section 3.2.3A(e) and (f) of Schedule 1 of the Operating Agreement to correct the description of the appropriate calculation in Section 3.2.3A(e) and (f) as follows:

> (e) In determining the Synchronized Reserve Market Clearing Price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the expected Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) ~~the absolute value of~~ the difference between the expected 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 Synchronized Reserve set 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. The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to 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, times (B) ~~the absolute value of~~ 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 Synchronized Reserve set point for the generation 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. The opportunity costs for a Demand Resource shall be zero.

PJM did not intentionally set out to calculate Synchronized Reserve Market Clearing Price and the credit due to a Generating Market Buyer providing Tier 2 Synch Reserves in a manner that was inconsistent with the Operating Agreement. Rather, the absolute value reference was incorporated into Section 3.2.3A(e) and (f) erroneously and inadvertently when the section was originally inserted into the Operating Agreement, and the error went undetected until the Quality Project review. PJM acted in good faith in calculating the Synchronized Reserve Market Clearing Price and the

credit due to a Generating Market Buyer providing Tier 2 Synch Reserves by multiplying the reduction in Tier 2 cleared MW by the *positive difference* between LMP and the offer price rather than using the absolute value because this is the appropriate methodology for calculating such clearing price and credits, despite the fact that the Operating Agreement language says otherwise. PJM has also acted in good faith by expeditiously presenting this issue to its stakeholders, explaining how the error occurred and proposing revisions to its Operating Agreement to correct the calculation.

B. The Requested Waiver is of Limited Scope

The requested waiver applies to the finite period – from March 2003 when Section 3.2.3A(e) and (f) was originally inserted into the Operating Agreement through February 2012 when it will terminate upon the Commission's issuance of an order accepting the proposed revisions to Section 3.2.3A(e) and (f). Accordingly, the waiver request is of limited scope.[13]

C. The Waiver Will Remedy a Concrete Problem

The requested waiver will remedy a concrete problem.[14] For the reasons discussed above, Synchronized Reserve Market Clearing Price and the credit due to a

[13] *See e.g.*, *ISO-NE* at P 10 (finding that a requested waiver was of limited scope where it was a one-time waiver of one provision of the tariff affecting no other provision of the tariff); *Southwest Power Pool, Inc.*, 135 FERC ¶ 61,032 at P 12 (2011) (finding that a requested waiver to address an implementation error in the calculation of energy market prices was "limited and will not have undesirable consequences or unduly affect settled expectations").

[14] *See e.g.*, *PJM* at P 11 (finding that granting waiver of the application of the Operating Agreement's default provisions to a company whose default arose from the billing error would remedy a concrete problem because otherwise, PJM would be required to declare the company in default leaving it without the corresponding ability to re-pay those obligations through participating in PJM's markets); *ISO-NE* at P 11 (finding that waiver of a tariff requirement by which ISO-NE would have to file an amendment to its tariff as a result of an over-collection would solve a concrete problem because otherwise ISO-NE would be required to amend its tariff to return money to participants, which would require restating rates, creating a massive resettlement, and creating separate rates for a single month).

Generating Market Buyer providing Tier 2 Synch Reserves should not be computed based on the absolute value of the difference between LMP at the generation bus and the offer price for energy from the generation resource as currently Section 3.2.3A dictates. Thus, waiving PJM's technical violation of Section 3.2.3A(e) and (f) to calculate the same using the positive difference between LMP and the offer price, which is in fact the correct manner in which Synchronized Reserve Market Clearing Price and the methodology pursuant to which the credit should be computed, is in the best interest of ensuring an equitable, just and reasonable resolution to the problem.

D. Granting the Waiver Will Not Harm Third Parties

As explained above, the underlying error was related to an implementation flaw in the original drafting of the language of Section 3.2.3A(e) and (f). The manner in which PJM has calculated Synchronized Reserve Market Clearing Price and the related credit since the provision was originally incorporated into the Operating Agreement is correct and should have been the manner in which the calculation was originally reflected in the tariff language filed with the Commission on March 20, 2003 in Docket No. RT01-2-006. Accordingly, no third parties will be harmed by the waiver request.[15] To the contrary, granting the waiver will prevent harm to Market Participants by ensuring

[15] *See e.g.*, *PJM* at P 12 (finding that waiver of the application of the Operating Agreement's default provisions to a company whose default arose from a billing error would have no undesirable consequence, and would "not adversely affect any third parties and should avert the potential default risk to PJM members that could result if waiver was not granted"); *ISO-NE* at P 12 (finding that waiver of a tariff requirement by which ISO-NE would have to file an amendment to its tariff as a result of an over-collection would not harm third parties because "participants will be refunded the amount of the over-collection through [a] true-up mechanism over the next two years"); *CAISO* at P 11 (finding that waiver of certain tariff provisions to correct a data entry error "will have no adverse impacts on third parties"); *HTP* at P 12 (finding that parties worked in a good faith effort to satisfy their respective obligations under an interconnection agreement and an interconnection construction agreement and that waiver of the developer's obligation to post the full security for its project by a date certain was appropriate due to the specific facts presented).

that the Synchronized Reserve Market Clearing Prices and related credit are calculated correctly. No party can reasonably claim it will be "harmed" if correct prices are allowed to be upheld despite the fact that the calculation thereof was technically not consistent with the applicable section of the Operating Agreement.

Moreover, Section 1.10.8(e) of Schedule 1 of the Operating Agreement limits PJM's ability to make changes to energy market clearing prices after they have been posted, even if there was an error in the posted prices. Specifically, Section 1.10.8(e) provides that:

> (e) If the Office of the Interconnection discovers an error in prices and/or cleared quantities in the Day-ahead Energy Market, Real-time Energy Market, Ancillary Services Markets or Day Ahead Scheduling Reserve Market after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants of the error 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 Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the second business day following the initial publication of the results for the Day-ahead Scheduling Reserve Market and Day-ahead Energy Market. 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, together with all available supporting documentation, by no later than 5:00 p.m. of the fifth business day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the fifth business day following the initial publication of the results in the Day-ahead Scheduling Reserve Market and the Day-ahead Energy Market. 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 Ancillary Services Markets, Day-ahead Energy Market and Real-time Energy Market, and no later than 5:00 p.m. of the tenth calendar day following the initial publication of the results in the Day-ahead Scheduling Reserve Market.

> 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.

(emphasis added). This provision is important not only for PJM, but for its Market Participants and the sanctity of wholesale electricity markets as a whole because it provides all stakeholders with the assurance that they can reasonably rely on the finality of energy market clearing prices.

If, on the other hand, the Commission were to reject PJM's requested waiver and require that PJM recalculate Synchronized Reserve Market Clearing Prices going back to 2003, using an admittedly erroneous and improper calculation nonetheless, would do more harm to wholesale electricity markets than is justifiable in light of the circumstances at issue and would be "fundamentally unfair to market participants."[16]

Additionally, PJM requests that the Commission determine that PJM has not violated Section 3.2.3A by its failure to calculate the Synchronized Reserve Market Clearing Price in accordance with the incorrect language of Section 3.2.3A because doing so would be unjust, unreasonable, inequitable and contrary to the public interest of ensuring that energy market clearing prices are as accurate as possible.

Given that PJM's stakeholders have overwhelmingly endorsed and approved the revisions to Section 3.2.3A(e) and (f) to correctly describe the appropriate calculation of

[16] *Bangor-Hydro Electric Co. v. ISO New England, Inc.*, 97 FERC ¶ 61,339 at 62,590 (2001) (stating that clearing prices resulting from implementation error had been relied upon by market participants, and "to go back and change those prices . . . would do far more harm . . . than is justifiable or appropriate under the circumstances . . . and would be fundamentally unfair to market participants.")

Synchronized Reserve Market Clearing Price and the credit due to a Generating Market Buyer providing Tier 2 Synch Reserves, coupled with the fact that the current calculation described in the Operating Agreement is incorrect, and in order to ensure that just and reasonable rates are applied to address the prior, current and future calculations of these clearing prices and credits until PJM's proposed correction is accepted by the Commission, it is appropriate for the Commission to grant the limited waiver requests.

IV. Effective Date

PJM proposes an effective date of February 18, 2012 for the proposed Tariff, Operating Agreement and RAA revisions referenced herein. Therefore, PJM requests that the Commission issue an order on this filing by February 17, 2012.

V. Description of Submittal

This filing consists of the following:

1. This transmittal letter:
2. A chart describing the proposed Tariff, Operating Agreement and RAA revisions in detail (as Attachment A);
3. Electronic versions of the revisions to the Tariff, Operating Agreement and RAA in marked (showing the changes) form (as Attachment B); and
4. Electronic versions of the revisions to the Tariff, Operating Agreement and RAA in clean form (as Attachment C).

VI. Correspondence

The following individuals are designated for inclusion on the official service list in this proceeding and for receipt of any communications regarding this filing:

Jacqulynn B. Hugee
Assistant General Counsel
PJM Interconnection, L.L.C.
955 Jefferson Avenue
Norristown, Pennsylvania 19403
(610) 666-8208
hugeej@pjm.com

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
glazec@pjm.com

VII. Service

PJM has served a copy of this filing on all PJM Members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,[17] PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: http://www.pjm.com/documents/ferc-manuals/ferc-filings.aspx with a specific link to the newly-filed document, and will send an e-mail on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM Region[18] 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 24 hours of the filing. Also, a copy of this filing will be available on the FERC's eLibrary website located at the following link:

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

[18] PJM already maintains, updates and regularly uses e-mail lists for all PJM Members and affected state commissions.

http://www.ferc.gov/docs-filing/elibrary.asp in accordance with the Commission's regulations and Order No. 714.

VIII. Conclusion

For the reasons discussed herein, PJM respectfully requests that the Commission accept the proposed revisions to PJM's Tariff and Operating Agreement and grant its request for a limited waiver of Section 3.2.3A(e) and (f) by no later than February 17, 2012.

Respectfully submitted,

/s/ Jacqulynn B. Hugee

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
glazec@pjm.com

Jacqulynn B. Hugee
Assistant General Counsel - Markets
PJM Interconnection, L.L.C.
955 Jefferson Avenue
Norristown, Pennsylvania 19403
(610) 666-8208
hugeej@pjm.com

Attachment A

(Chart of Proposed Revisions to Tariff, Operating Agreement and RAA)

Legend for PJM Section Title Column
Quality Project revision
Non-Quality Project revision

Substantive Revisions, and Non-Substantive and Ministerial Corrections to the PJM OATT, OA & RAA Proposed Effective Date for All Section is February 18, 2012						
No.	PJM Section Title	Record ID	Version	Priority Code	Reason for Proposed Revision	Proposed Revision
PJM Tariff						
1.	OATT, §110.1 (Application)	307	1.0.0	500	Revised reference to "existing Generation Capacity Resource" to the defined term "Existing Generation Capacity Resource."	The Generation Interconnection Customer desiring the interconnection of a new Generation Capacity Resource of 20 MW or less or the increase in capacity, by 20 MW or less, of an Eexisting Generation Capacity Resource, must submit a completed Attachment N – Form of Generation Interconnection Feasibility Study Agreement. Attachment N of the PJM Tariff may be found on the PJM web site at and must be submitted to Transmission Provider.
2.	OATT, §110.5 (Interconnection Service Agreement)	311	1.0.0	500	Revised reference to "existing Generation Capacity Resource" to the defined term "Existing Generation Capacity Resource."	As with larger generation projects, an Interconnection Service Agreement must be executed and filed with the FERC. The Interconnection Service Agreement identifies the obligations, on the part of the Interconnection Customer, to pay for transmission facilities required to facilitate the interconnection and the Capacity Interconnection Rights which are awarded to the *Generation* Capacity Resource. In general, the execution of an Interconnection Service Agreement is no different for capacity additions of 20 MW or less than for larger *Generation* Capacity Resources. However, in instances where an increase of 20 MW or less to an Eexisting *Generation* Capacity Resource can be put in service immediately, a modified Interconnection Service Agreement may be executed. If such an increase is expedited through the System Impact Study phase, ahead of larger projects already in the New Services Queue, an Interconnection Service Agreement will be executed granting interim Capacity Interconnection Rights. These interim rights will allow the capacity increase to be implemented and the resource to participate in the capacity market until studies have been completed for earlier queued resources and all related obligations have been defined. At such time, the interim rights awarded the smaller capacity addition will become dependent on the construction of any required transmission facilities and the satisfaction of any financial obligations for those facilities. If, once those obligations are defined, the smaller capacity addition desires to retain the interim Capacity Interconnection Rights; a new Interconnection Service Agreement will be executed.
3.	OATT, Schedule 2 (Reactive Supply and Voltage Control from Generation or Other Sources Service)	505	2.0.0	500	The tariff language does not accurately reflect current practice. PJM performs the calculation daily, dividing by the actual number of hours in each day (recognizing daylight savings time changes) and then totals for the month.	**Charges** Purchasers of Reactive Supply and Voltage Control from Generation or Other Sources Service shall be charged for such service in accordance with the following formulae. Monthly Charge for a purchaser receiving Network Integration Transmission Service or Point-to-Point Transmission Service to serve Non-Zone Load = Allocation Factor * Total Generation or other source Owner Monthly Revenue Requirement

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						Monthly Charge for a purchaser receiving Network Integration Transmission Service or Point-to-Point Transmission Service to serve Zone Load = Allocation Factor * Zonal Generation or other source Owner Monthly Revenue Requirement * Adjustment Factor Where: Purchaser serving Non-Zone Load is a Network Customer serving Non-Zone Network Load or serving Network Load in a zone with no revenue requirement for Reactive Supply and Voltage Control from Generation or Other Sources Service, or a Transmission Customer where the Point of Delivery is at the boundary of the PJM Region. Zonal Generation or other source Owner Monthly Revenue Requirement is the sum of the monthly revenue requirements for each generator or other source located in a Zone, as such revenue requirements have been accepted or approved, upon application, by the Commission. Total Generation or other source Owner Monthly Revenue Requirement is the sum of the Zonal Generation or other source Owner Monthly Revenue Requirements for all Zones in the PJM Region. Allocation Factor is the monthly transmission use of each Network Customer or Transmission Customer per Zone or Non-Zone, as applicable, on a megawatt basis divided by the total transmission use in the Zone or in the PJM Region, as applicable, on a megawatt basis. For Network Customers, monthly transmission use on a megawatt basis is the sum of a Network Customer's daily values of DCPZ or DCPNZ (as those terms are defined in Section 34.1) as applicable, for all days of the month. For Transmission Customers, monthly transmission use on a megawatt basis is the sum of the Transmission Customer's hourly amounts of Reserved Capacity for each day of~~in~~ the month (not curtailed by PJM) divided by the number of hours in the day~~24~~. Adjustment Factor is determined as the sum of the total monthly transmission use in the PJM Region, exclusive of such use by Transmission Customers serving Non-Zone Load, divided by the total monthly transmission use in the PJM Region on a megawatt basis.
4.	OATT, Schedule 3	506	2.0.0	500	Language infers that there are multiple	Regulation and Frequency Response Service is necessary to provide for the continuous balancing of

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	(Regulation and Frequency Response Service)				regulation zones should be deleted. As of 2006, there is a single RTO regulation market (zone) with a single objective (requirement). Additionally, references to "Control Zone" need to be replaced with "Regulation Zone". Provision should be revised to use the defined term "Regulation" rather than "regulation."	resources ~~(generation and interchange)~~ with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line resources ~~generation~~ whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The amount of and charges for Regulation and Frequency Response Service are set forth below. The Transmission Provider shall administer the purchases of Regulation Service in the PJM Interchange Energy Market. PJMSettlement shall be the Counterparty to the purchases by customers of Regulation Service in the PJM Interchange Energy Market; provided however, that PJMSettlement shall not be the contracting party to bilateral transactions between market participants or with respect to a self-schedule or self-supply of ~~generation~~ resources by a customer to satisfy its Regulation obligation. For ~~r~~Regulation not satisfied by individual Transmission Owners on behalf of their Native Load Customers, Network Customers or other Transmission Customers serving load in the PJM Region, the Transmission Provider will order the lowest cost alternative for ~~r~~Regulation in service as needed to meet the ~~r~~Regulation requirements of each Regulation Zone (as may be set forth in the PJM Manuals~~)~~, and as specified below: a. Regulation shall be supplied to meet the Regulation objective of a Regulation Zone from ~~generators~~resources located within the metered electrical boundaries of such Regulation Zone. Resources~~Generators~~ offering ~~r~~Regulation shall comply with applicable standards and requirements for ~~r~~Regulation capability and dispatch specified in the procedures of the Office of the Interconnection. b. The Office of the Interconnection shall obtain and maintain an amount of ~~r~~Regulation for each Regulation Zone equal to the Regulation objective for such Regulation Zone, as specified in its procedures. c. The ~~r~~Regulation range of a resource~~unit~~ shall be at least twice the amount of ~~r~~Regulation assigned. d. A resource~~unit~~ capable of automatic energy dispatch that is also providing ~~r~~Regulation shall have its energy dispatch range reduced from the ~~r~~Regulation range by twice the amount of the ~~r~~Regulation provided. The amount of ~~r~~Regulation provided by a resource~~unit~~ shall serve to redefine the normal minimum generation and normal maximum generation energy limits of that unit, in that the amount of ~~r~~Regulation shall be added to the unit's normal minimum generation energy limit, and

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						subtracted from its normal maximum generation energy limit. e. Qualified ~~r~~Regulation must satisfy the verification tests described in the procedures of the Office of the Interconnection. f. A Transmission Owner, Network Customer or other Transmission Customer may satisfy its ~~r~~Regulation obligation from its own resources capable of performing ~~r~~Regulation service, by contractual arrangements with others able to provide ~~r~~Regulation service on a comparable basis, or by purchases from~~, as applicable,~~ the PJM ~~r~~Regulation market. ~~in the MAAC Control Zone, the regulation market in the VACAR Control Zone or the regulation market in the PJM West Region.~~ g. The Office of the Interconnection shall obtain ~~r~~Regulation service from the least-cost alternatives available from either pool-scheduled or self-scheduled resources as needed to meet Regulation~~Control~~ Zone requirements not otherwise satisfied by a Transmission Owner, Network Customer or other Transmission Customer, in accordance with Section 1.11.4(b) of Attachment K-Appendix. h. The Office of the Interconnection shall dispatch resources for ~~r~~Regulation by sending ~~r~~Regulation signals and instructions to resources from which ~~r~~Regulation service has been offered, in accordance with the procedures of the Office of the Interconnection. Those resources shall comply with ~~r~~Regulation dispatch signals and instructions transmitted by the Office of the Interconnection and, in the event of conflict, ~~r~~Regulation dispatch signals and instructions shall take precedence over energy dispatch signals and instructions. Those providing ~~r~~Regulation shall exert all reasonable efforts to operate, or ensure the operation of, their resources supplying load in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice. i. Each Transmission Owner (on behalf of its Native Load Customers), Network Customer or other Transmission Customer serving load within a ~~Control~~Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such ~~Control~~Regulation Zone for such hour, based on the entity's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such ~~Control~~Regulation Zone for such hour. j. An entity supplying ~~r~~Regulation at the direction of the Office of the Interconnection in excess of its hourly ~~r~~Regulation obligation shall be credited for each increment of such ~~r~~Regulation at the price specified in Sections 3.2.2 and 3.3.2 of Attachment K-Appendix. A Transmission Owner, Network Customer or other Transmission Customer that does not meet its hourly ~~r~~Regulation obligation shall be charged for ~~r~~Regulation dispatched by the Office of the Interconnection to meet such obligation at the price specified in Sections 3.2.2 and 3.3.2 of Attachment K-Appendix.
5.	OATT, Schedule 6A (Regulation and Frequency Response Service)	510	3.0.0	500	The tariff language does not accurately reflect current practice. PJM performs the calculation daily, dividing by the actual number of hours in each day	**Charges** . . . 25. Purchasers of Black Start Service shall be charged for such service in accordance with the following formulae.

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	(See also OATT Schedule 2)				(recognizing daylight savings time changes) and then totals for the month.	Monthly Charge for a purchaser receiving Network Integration Transmission Service or Point-to-Point Transmission Service to serve Non-Zone Load = Allocation Factor * Total Generation Owner Monthly Black Start Service Revenue Requirement Monthly Charge for a purchaser receiving Network Integration Transmission Service or Point-to-Point Transmission Service to serve Zone Load = Allocation Factor * Zonal Generation Owner Monthly Black Start Service Revenue Requirement * Adjustment Factor Where: Purchaser serving Non-Zone Load is a Network Customer serving Non-Zone Network Load or a Transmission Customer where the Point of Delivery is at the boundary of the PJM Region. Zonal Generation Owner Monthly Black Start Service Revenue Requirement is the sum of the monthly Black Start Service revenue requirements for each generator nominated by the Transmission Owners in that zone. Total Generation Owner Monthly Black Start Service Revenue Requirement is the sum of the Zonal Generation Owner Monthly Black Start Service Revenue Requirements for all Zones in the PJM Region. Allocation Factor is the monthly transmission use of each Network Customer or Transmission Customer per Zone or Non-Zone, as applicable, on a megawatt basis divided by the total transmission use in the Zone or in the PJM Region, as applicable, on a megawatt basis. For Network Customers, monthly transmission use on a megawatt basis is the sum of a Network Customer's daily values of DCPZ or DCPNZ (as those terms are defined in Section 34.1) as applicable, for all days of the month. For Transmission Customers, monthly transmission use on a megawatt basis is the sum of the Transmission Customer's hourly amounts of Reserved Capacity for each day of~~in~~ the month (not curtailed by PJM) divided by the number of hours in the day~~24~~. Adjustment Factor is determined as the sum of the total monthly transmission use in the PJM Region on a megawatt basis, exclusive of such use by Network Customers and Transmission Customers serving Non-Zone Load, divided by the total monthly transmission

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						use in the PJM Region on a megawatt basis.
6.	OATT, Attachment K, (Preface)	548	1.0.0	500	The Transmission Congestion Charge section in Attachment K does not properly reflect Marginal Losses. This was section was apparently not accurately revised when marginal losses were implemented. Rather than repeat generally in Attachment K what is already specifically and accurately reflected in Attachment K-Appendix and risk having discrepancies in the respective provisions, it was determined that the best option was to revise Attachment K to cross-reference the provisions in Attachment K-Appendix.	**Transmission Congestion and Loss Charges and Credits** **Preface**. This Attachment and Attachment K – Appendix specify~~ies~~ the manner in which all Transmission Customers, Network Customers, and Transmission Owners using the Transmission System to serve their Native Load Customers and Market Participants submitting virtual bids and offers ~~(all of the foregoing being referred to as "Transmission Users"),~~ will be charged for the costs of congestion and losses on the Transmission System, ~~(as set forth in section A) and specifies~~ the manner in which all FTR holders share in the allocation of revenues received as Transmission Congestion Charges ~~(as set forth in section B),~~ and the manner in which Network Service Users, Market Participants in the PJM Interchange Energy Market and Transmission Customers share in the allocation of Transmission Loss Charges. ~~The provisions of this Attachment will apply to all Transmission Users, whether they are using the Transmission System for delivery of their own resources to load, for bilateral transactions, or to purchase or sell energy in the PJM Interchange Energy Market.~~ In addition, ~~the appendices to this~~ Attachment K – Appendix incorporates into the Tariff for ease of reference the provisions of Schedule 1 of the Operating Agreement ("Schedule 1"). Capitalized terms used in this Attachment which are not defined in the Tariff or in the Attachment, but which are defined in Schedule 1 shall have the meanings set forth in Schedule 1.
7.	OATT Attach K Section A. Transmission Congestion Charges (Title Only)	549	1.0.0	500	The Transmission Congestion Charge section in Attachment K does not properly reflect Marginal Losses. This was section was apparently not accurately revised when marginal losses were implemented. Rather than repeat generally in Attachment K what is already specifically and accurately reflected in Attachment K-Appendix and risk having discrepancies in the respective provisions, it was determined that the best option was to revise Attachment K to cross-reference the provisions in Attachment K-Appendix.	**A. Transmission Congestion and Loss Charges**

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8.	OATT Attach K Section A1. General. [Reserved for Future Use]	550	1.0.0	500	The Transmission Congestion Charge section in Attachment K does not properly reflect Marginal Losses. This was section was apparently not accurately revised when marginal losses were implemented. Rather than repeat generally in Attachment K what is already specifically and accurately reflected in Attachment K-Appendix and risk having discrepancies in the respective provisions, it was determined that the best option was to revise Attachment K to cross-reference the provisions in Attachment K-Appendix.	1. [Reserved for Future Use] ~~General.~~ ~~Every Transmission User will be charged for the costs of congestion on the Transmission System on the basis of the difference between the Locational Marginal Price at the location or locations on the Transmission System where the Transmission User supplies energy for transmission and the location or locations where the Transmission User withdraws energy from the Transmission System. To implement these charges, the Office of the Interconnection will calculate credits for every Transmission User based on the Locational Marginal Price at the location or locations at which the Transmission System receives energy from the Transmission User, calculated in accordance with section A(2) of this Attachment, and will calculate debits based on the Locational Marginal Price at the location or locations to which the Transmission User uses the Transmission System to deliver energy, calculated in accordance with section A(3) of this Attachment. The difference, if any, between these credits and debits, less the Transmission User's net payments for purchases and sales in the PJM Interchange Energy Market, represents the Transmission Congestion Charges borne by the Transmission User. No additional Transmission Congestion Charges shall be assessed with respect to the Transmission User's sale or purchase of energy on the PJM Interchange Energy Market, because the price for the sale or purchase of such energy already reflects any differences between Locational Marginal Prices associated with the transaction.~~
9.	OATT Attach K Section A2. Credits to Transmission Users [Reserved for Future Use]	551	1.0.0	500	The Transmission Congestion Charge section in Attachment K does not properly reflect Marginal Losses. This was section was apparently not accurately revised when marginal losses were implemented. Rather than repeat generally in Attachment K what is already specifically and accurately reflected in Attachment K-Appendix and risk having discrepancies in the respective provisions, it was determined that the best option was to revise Attachment K to cross-reference the provisions in Attachment K-Appendix.	2. [Reserved for Future Use] ~~Credits to Transmission Users.~~ ~~(a) For each hour during the day, each Transmission User shall be credited with the sum of the amounts determined in accordance with the following formula for each of the busses at which the Transmission User causes the Transmission System to receive electric energy:~~ ~~Credit for Each Bus = Generation * Hourly LMP~~ ~~where~~ ~~Generation = The energy supplied by the Transmission User at the bus during the hour, measured in whole megawatts, as determined (i) in the case of a bus within the PJM Region, by the Office of the Interconnection utilizing the State Estimator model described in Section 2 of Schedule 1, and (ii) in the case of a bus at the border of such area, by the Transmission User's transaction request.~~ ~~Hourly LMP = the integrated hourly Locational Marginal Price (LMP) at the bus, calculated by the Office of the Interconnection based on five minute values; and~~

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						~~LMP - the cost to serve the next increment of load at the bus at the lowest possible price consistent with the preservation of reliability and transmission system conditions, determined as described in Section 2 of Schedule 1.~~ ~~(b) Credits shall be calculated in accordance with subsection (a) for each generation bus in the PJM Region and for each bus representing an interconnection between such area and an adjacent control area. The total of the amounts determined in accordance with subsection (a) for all of the locations at which a Transmission User supplies energy for receipt by the Transmission System shall be summed for that Transmission User.~~
10.	OATT Attach K Section A3. Debits to Transmission Users. [Reserved for Future Use]	552	1.0.0	500	The Transmission Congestion Charge section in Attachment K does not properly reflect Marginal Losses. This was section was apparently not accurately revised when marginal losses were implemented. Rather than repeat generally in Attachment K what is already specifically and accurately reflected in Attachment K-Appendix and risk having discrepancies in the respective provisions, it was determined that the best option was to revise Attachment K to cross-reference the provisions in Attachment K-Appendix.	3. [Reserved for Future Use]~~Debits to Transmission Users~~ ~~(a) For each hour during the day, each Transmission User shall be debited the sum of the amounts determined in accordance with the following formula for each of the busses to which the Transmission System delivers electric energy for the Transmission User:~~ ~~Debit for Each Bus = (Load) * Hourly LMP~~ ~~where~~ ~~Load = the load at the bus during the hour, measured in whole megawatts, determined: (i) in the case of a bus within the PJM Region, by the Office of the Interconnection utilizing the State Estimator model described in Section 2 of Schedule 1 and the portion of such load at the bus attributable to the Transmission User; or (ii) in the case of a bus at the border of such area, by the Transmission User's transaction request;~~ ~~Hourly~~ ~~LMP = The integrated hourly Locational Marginal Price (LMP) at the bus, calculated by the Office of the Interconnection based on five minute values; and~~ ~~LMP = The cost to serve the next increment of load at the bus at the lowest possible price consistent with the preservation of reliability and transmission system conditions, determined as described in Section 2 of Schedule 1.~~ ~~(b) Debits shall be calculated in accordance with subsection (a) for each load bus in the PJM Region and for each bus representing an interconnection between such area and an adjacent control area. The total of the amounts determined in accordance with subsection (a) for all of the locations at~~

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						~~which a Transmission User receives energy delivered by the Transmission System shall be summed for that Transmission User.~~
11.	OATT Attach K Section A4. Offset of Credits and Debits to	553	2.0.0	500	The Transmission Congestion Charge section in Attachment K does not properly reflect Marginal Losses. This was section was apparently not accurately revised when marginal losses were implemented. Rather than repeat generally in Attachment K what is already specifically and accurately reflected in Attachment K-Appendix and risk having discrepancies in the respective provisions, it was determined that the best option was to revise Attachment K to cross-reference the provisions in Attachment K-Appendix.	~~4. Offset of Credits and Debits to a Transmission User.~~ In determining the total billable amount of Transmission Congestion Charges, ~~T~~the Office of the Interconnection, on behalf of PJMSettlement, shall take into account and set-off against each other both positive Transmission Congestion Charges and negative Transmission Congestion Charges ~~amounts credited to a Transmission User~~ in accordance with Section 5 of ~~A(2) of this~~ Attachment K – Appendix ~~and amounts debited to a Transmission User in accordance with Section A(3) of this Attachment, and~~ PJMSettlement shall exclude ~~the Transmission User's~~ transactions on the PJM Interchange Energy Market~~,~~ in issuing a statement, invoice, or payment for the net amount owed ~~to or by that Transmission User~~ for Transmission Congestion Charges for any period. In determining the total billable amount of Transmission Loss Charges, the Office of the Interconnection, on behalf of PJMSettlement, shall take into account and set-off against each other both positive Transmission Loss Charges and negative Transmission Loss Charges in accordance with Section 5 of Attachment K – Appendix. PJMSettlement shall exclude transactions on the PJM Interchange Energy Market in issuing a statement, invoice, or payment for the net amount owed for Transmission Loss Charges for any period.
12.	OATT Attach K Section B. Transmission Congestion Credits.	554	1.0.0	500	The Transmission Congestion Charge section in Attachment K does not properly reflect Marginal Losses. This was section was apparently not accurately revised when marginal losses were implemented. Rather than repeat generally in Attachment K what is already specifically and accurately reflected in Attachment K-Appendix and risk having discrepancies in the respective provisions, it was determined that the best option was to revise Attachment K to cross-reference the provisions in Attachment K-Appendix.	**B. Transmission Congestion and Loss Credits.**
13.	OATT Attach K Section B1. General.	555	1.0.0	500	The Transmission Congestion Charge section in Attachment K does not properly reflect Marginal Losses. This was section was apparently not	~~1. General.~~ Financial Transmission Rights may be acquired by purchase in the Financial Transmission Rights auctions or in the secondary market provided for in Section 7 of Attachment K - Appendix. ~~The Office~~

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					accurately revised when marginal losses were implemented. Rather than repeat generally in Attachment K what is already specifically and accurately reflected in Attachment K-Appendix and risk having discrepancies in the respective provisions, it was determined that the best option was to revise Attachment K to cross-reference the provisions in Attachment K-Appendix.	~~of the Interconnection will post information on the OASIS regarding FTR auction results, FTR transfers, including which FTRs have been transferred, the amount of the transfer (MW), the duration of the transfer and the identity of the buyer and seller.~~ ~~For a new PJM zone, each Transmission Customer purchasing Firm Point-to-Point Service, each Network Customer, with respect to its reservation of firm transmission service for deliveries from Network Resources to Network Load, and each Transmission Owner with respect to its reservation of firm transmission service for the delivery of energy from Generation Capacity Resources to Native Load Customers (any of the foregoing being referred to as a "Firm Transmission User"), shall receive Financial Transmission Rights ("FTRs") corresponding to points of receipt and delivery designated for their firm uses of the Transmission System. Such FTRs shall remain in effect until the first annual allocation of Auction Revenue Rights to occur after the integration of such new PJM zone into the PJM Interchange Energy Market.~~ Each holder of an FTR shall receive the total Transmission Congestion Credits determined in accordance with Section ~~B(2)~~ of ~~this~~ Attachment K – Appendix. Each Network Service User and Transmission Customer shall receive an allocation of Transmission Loss Credits in accordance with Section 5 of Attachment K – Appendix.
14.	OATT Attach K Section B2. Determination of Credit. [Reserved for Future Use]	556	2.0.0	500	The Transmission Congestion Charge section in Attachment K does not properly reflect Marginal Losses. This was section was apparently not accurately revised when marginal losses were implemented. Rather than repeat generally in Attachment K what is already specifically and accurately reflected in Attachment K-Appendix and risk having discrepancies in the respective provisions, it was determined that the best option was to revise Attachment K to cross-reference the provisions in Attachment K-Appendix.	2. [Reserved for Future Use] ~~Determination of Credit.~~ ~~(a) Overview. For each hour with respect to which the Transmission Provider receives payments of Transmission Congestion Charges, determined in accordance with section A of this Attachment, Transmission Congestion Credits shall be allocated to the holders of Financial Transmission Rights. As explained in subsection B(1) above, the Financial Transmission Rights are associated with the points on the Transmission System between which the Firm Transmission User to whom the FTR was originally issued has arranged for the firm transmission of electric energy, whether on a network or point-to-point basis. Holders of FTRs receive credits attributable to the difference, if any, between Congestion Prices at the Point or Points of Receipt and the Point or Points of Delivery associated with the Financial Transmission Rights. As explained in Section 5.2.2 of Attachment K – Appendix, each FTR holder shares in Transmission Congestion Credits to the extent it holds Financial Transmission Rights between the Point or Points of Receipt and the Point or Points of Delivery at which congestion is experienced in a particular hour. Distribution of credits in this manner ensures that each FTR holder will not incur energy costs that are greater than the costs of energy from the generation resources associated with the FTR holder's Financial Transmission Rights. Target allocations of Transmission Congestion Credits to holders of Financial Transmission~~

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						~~Rights are calculated in accordance with Section 5.2.5 of Attachment K – Appendix and Transmission Congestion Credits are distributed in accordance with that allocation, as described in Sections 5.2.5 and 5.2.6 of Attachment K – Appendix.~~ ~~(b) **Assignment of Financial Transmission Rights.** Financial Transmission Rights shall be obtained pursuant to Attachment K - Appendix.~~ ~~(c) **Assignment of Auction Revenue Rights.** Auction Revenue Rights shall be assigned pursuant to Attachment K - Appendix.~~ ~~(d) **Target Allocation of Credits to Financial Transmission Rights.** Target Allocation of Transmission Congestion Credits for each FTR holder for each hour shall be pursuant to Attachment K – Appendix.~~ ~~(e) **Distribution of Transmission Congestion Credits.** Distribution of Transmission Congestion Credits shall be pursuant to Attachment K – Appendix.~~
15.	OATT Attach K Section C. Offset of Transmission Congestion [Reserved for Future Use]	557	3.0.0	500	The Transmission Congestion Charge section in Attachment K does not properly reflect Marginal Losses. This was section was apparently not accurately revised when marginal losses were implemented. Rather than repeat generally in Attachment K what is already specifically and accurately reflected in Attachment K-Appendix and risk having discrepancies in the respective provisions, it was determined that the best option was to revise Attachment K to cross-reference the provisions in Attachment K-Appendix.	C. [Reserved for Future Use] ~~Offset of Transmission Congestion Charges and Transmission Congestion Credits.~~ ~~The Office of the Interconnection, on behalf of PJMSettlement, shall take into account both (i) amounts payable by a Transmission User with respect to Transmission Congestion Charges as determined in accordance with Section A of this Attachment, and (ii) amounts payable to a Transmission User with respect to Transmission Congestion Credits as determined in accordance with Section B of this Attachment.~~
16.	OATT Attachment K Section D	1502	2.0.0	500	The Transmission Congestion Charge section in Attachment K does not properly reflect Marginal Losses. This was section was apparently not accurately revised when marginal losses were implemented. Rather than repeat	**D. Transmission Service Components.** Transmission Congestion Charges~~,~~ ~~and~~ Transmission Congestion Credits, Ancillary Services charges and credits, Transmission Loss Charges, Transmission Loss Credits and allocations of Financial Transmission Rights auction revenues ~~to a Transmission User~~ are components of transmission service charges under Parts II and III of the Tariff and shall not give rise to separate transactions with

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					generally in Attachment K what is already specifically and accurately reflected in Attachment K-Appendix and risk having discrepancies in the respective provisions, it was determined that the best option was to revise Attachment K to cross-reference the provisions in Attachment K-Appendix.	PJMSettlement regarding the purchase or sale of electric energy.
17.	OATT Attachment K Section 1.10, specifically §1.10.1A(h) (Scheduling - General)	571	7.0.0	500	Day-ahead scheduled loads are not posted on OASIS but are posted in eMKT.	The Office of the Interconnection shall post ~~on the PJM Open Access Same-time Information System~~ 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.
18.	OATT Attachment K Section 1.10, specifically §1.10.5(b) (Scheduling – External Resources)	571 Continued	7.0.0	500	PJM's eMKT does not support multiple offers from an aggregated external resource. While the market is open, anything about offers can be changed. Once an offer is submitted in eMKT and the market closes, it can't be withdrawn.	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. ~~If a Market Seller submits more than one offer on an aggregated resource basis, the withdrawal of any such offer shall be deemed a withdrawal of all higher priced offers for the same period.~~
19.	OATT Attachment K Section 1.10, specifically §1.10.6(a) (Scheduling – External Market Buyers)	571 Continued	7.0.0	500	This calculation should not be limited to load busses. Revision to make bus reference general so as to include interface busses. In addition, Day-ahead and Real-time pricing can both be applied in the same hour and Market Buyers can be Market Sellers at the same time but focus should be on load busses.	Deliveries to an External Market Buyer not subject to dynamic dispatch by the Office of the Interconnection shall be delivered on a block loaded basis to the ~~load~~ 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) ~~or credited~~ at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing ~~load~~bus or buses.
20.	OATT Attachment K Section 1.10, specifically	571 Continued	7.0.0	500	PJM notifies the market of significant changes that could affect market	(b) Not earlier~~later~~ than 4:00 p.m. of the day before each Operating Day, or such other~~earlier~~ deadline as may be specified by the Office of the Interconnection in the PJM Manuals, the Office of

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	§1.10.8(b), (c) and (d) (Scheduling – Office of the Interconnection Responsibilities)				decisions. However the specific information listed in subsection (c) is not provided. The language that PJM seeks to delete from subsection (c) was formerly also included in subsection (b), which was deleted in a filing submitted on March 10, 2000 in Docket No. ER00-1849-000, the "two settlement system filing" that established PJM's Day-ahead Energy Market. The transmittal letter for this filing doesn't explain why the language was removed from subsection (b) but not from subsection (c). PJM believes the day-ahead market mooted the need for an initial estimate of congestion and that the same logic would have applied all along to the LMP-based real-time market and mooted the need for a revised estimate of congestion as well. Thus, the language should have been removed from subsection (c) in that same 2000 filing. The removal of the referenced language will not alleviate PJM's obligation to post helpful planning information. Operating Agreement, Schedule 6, Subsection (f) states: "The Office of the Interconnection will also provide access through the PJM website, to the planning criteria and assumptions used by the Transmission Owners for the development of the current Local Plan." Subsection (e) states that FERC Form No. 715 material will be posted on the	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. (c) Following posting of the information specified in Section 1.10.8(b), 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.~~—The Office of the Interconnection shall post on the PJM Open Access Same-time Information System at times specified in the PJM Manuals a revised forecast of the location and duration of any expected transmission congestion, and of the range of differences in Locational Marginal Prices between major subareas of the PJM Region expected to result from such transmission congestion.~~ (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 offer that set 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 offer that set the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Section 3.3A of this Schedule.

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					PJM website.	
21.	OATT Attachment K Section 1.11, specifically §1.11.4(b) (Regulation)	572	2.0.0	500	There is a conflict in the provision and the design of the software program that determines how resources should be dispatched with respect to how Regulation offer ties are broken. Software provides that for price-tied regulation offers are dispatched in order of their MW values. The tie-breaking is implemented in the optimization software. Therefore, the provision should be revised to delete the incorrect language.	The Office of the Interconnection shall obtain Regulation service from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Demand Resources as needed to meet Regulation Zone requirements not otherwise satisfied by the Market Buyers. Generation resources or Demand Resources offering to sell Regulation shall be selected to provide Regulation on the basis of each generation resource's and Demand Resource's regulation offer and the estimated opportunity cost of a resource providing regulation and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Regulation, and other ancillary services. Estimated opportunity costs for generation resources shall be determined by the Office of the Interconnection on the basis of the expected value of the energy sales that would be foregone or uneconomic energy that would be produced by the resource in order to provide Regulation, in accordance with procedures specified in the PJM Manuals. Estimated opportunity costs for Demand Resources will be zero. ~~If the Office of the Interconnection is not able to distinguish resources offering Regulation on the basis of their regulation offers and estimated opportunity costs, resources shall be selected on the basis of the quality of Regulation provided by the resource as determined by tests administered by the Office of the Interconnection.~~
22.	OATT, Attachment K – Appendix Section 3.2, specifically §3.2.1(d) (Spot Market Energy Charges)	585	9.0.0	500	Provision does not allow for Internal Market Buyers to have amounts scheduled in the Day-ahead Energy Market. Clean up language to delete "the External" replace with "such."	At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the total amount of net hourly PJM Interchange for each Market Buyer, including Generating Market Buyers, in accordance with the PJM Manuals. For Internal Market Buyers that are Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall include determination of the net energy flows from: (i) tie lines; (ii) any generation resource the output of which is controlled by the Market Buyer but delivered to it over another entity's Transmission Facilities; (iii) any generation resource the output of which is controlled by another entity but which is directly interconnected with the Market Buyer's transmission system; (iv) deliveries pursuant to bilateral energy sales; (v) receipts pursuant to bilateral energy purchases; and (vi) an adjustment to account for the day-ahead PJM Interchange, calculated as the difference between scheduled withdrawals and injections by that Market Buyer in the Day-ahead Energy Market. For External Market Buyers and Internal Market Buyers that are not Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall determine the energy scheduled hourly for delivery to the Market Buyer net of the amounts scheduled by such ~~the External~~ Market Buyer in the Day-ahead Energy Market.
23.	OATT, Attachment K – Appendix Section 3.2, specifically §3.2.3(a) (Operating Reserves)	585 Continued	9.0.0	500	There is no Section 3.2.A.01. The correct section reference is 3.2.3A.01.	A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the prices offered 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 Section 3.2.3A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, the Office of the Interconnection shall schedule additional Operating Reserves

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						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 Scheduling Reserves Requirement.
24.	OATT, Attachment K – Appendix Section 3.2, specifically §3.2.3(e) (Operating Reserves)	585 Continued	9.0.0	500	PJM doesn't calculate operating reserve credits separately for units committed solely for Synch Reserves. Therefore, the language indicating to the contrary should be deleted. A "period" can be one hour or a range of hours. The reference to "period" in the referenced section is incorrect because Synch Reserve credits are netted against Operating Reserve credits on an hourly basis, not by period. Thus, the reference to "period" in the section should be changed to "hour." Additionally, after PJM implemented segmented make whole payments, the reference to contiguous hours is no longer accurate. Netting is done only on an hourly basis now. Therefore, the reference to contiguous hours must e deleted.	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. ~~and that is not committed solely for the purpose of providing Synchronized Reserve.~~ 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 or minimum run time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or minimum run time (minimum down time for Demand 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 (minimum down time for Demand Resources) and Segment 2 will include the remainder of the contiguous hours 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. . . . Synchronized Reserve and Day-ahead Scheduling Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding hour(s) in which the Synchronized Reserve and Day-ahead Scheduling Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each hour~~period~~ the unit operates in condensing and generation mode ~~for one or more contiguous hours~~.
25.	OATT, Attachment K – Appendix Section 3.2, specifically §3.2.3(f) (Operating Reserves)	585 Continued	9.0.0	500	The Operating Reserve Lost Opportunity Cost Credits provision was not written to cover the Regulation and Synch Reserve in the same hour. Therefore the provision should be clarified to reflect this possibility. Manual 28 also addresses this issue.	A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool scheduled (or self-scheduled, if operating according to 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 hourly integrated, 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 hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)},

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						where: 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 hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments; AG equals the actual hourly integrated output of the unit; URTLMP equals the real time LMP at the unit's bus; UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and where URTLMP - UB shall not be negative.
26.	OATT, Attachment K – Appendix Section 3.2, specifically §3.2.3(f-2) (Operating Reserves)	585 Continued	9.0.0	500	Section 3.2.2A(d) does not exist. The correct section reference should be 3.2.2(d).	A Market Seller's hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to 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~~A~~(d) and 3.2.3A(f) and further detailed in the PJM Manuals.
27.	OATT, Attachment K – Appendix Section 3.2, specifically §3.2.3(j) and (k) (Operating Reserves)	585 Continued	9.0.0	500	Section 3.2.3(j) is not consistent with Section 3.2.3(k). Operating Reserve Synchronous Condensing Credits are no longer determined separately by Control Zone. Rather, Section 3.2.3(k) indicates that the allocation for all credits go to all load and exports in the PJM region.	(j) The sum of the foregoing credits as specified in Section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for ~~each Control Zone of~~ the PJM Region ~~based on the Control Zone to which the resource was synchronized to provide synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation~~. (k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency

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						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 (net of operating Behind The Meter Generation, but not to be less than zero) 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 dynamically scheduled to load outside ~~such Control Zone~~the PJM Region pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.
28.	OATT, Attachment K – Appendix Section 3.2, specifically §3.2.3(o) (Operating Reserves)	585 Continued	9.0.0	500	In some scenarios the UDS Case is unavailable, the ramp-limited desired MW from markets is false and the bad limits indicator is also false. Manual 28 specifies that in such case PJM must use UDS LMP desired MW in the referenced calculation of Operating Reserves The provision should be revised to specify how PJM makes its calculation. The bad limits indicator is in the deviation report. When it is false, it reflects real-time limits as being more restrictive than day-ahead limits, and can raise the economic minimum and lower the economic maximum.	To determine if a 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 UDS Basepoint or the actual output and ramp-limited desired MW value. The % off dispatch and MW off dispatch will be a time-weighted average over the course of an hour. If the UDS Basepoint 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 UDS LMP Desired MW.
29.	OATT, Attachment K – Appendix Section 3.2, specifically §3.2.3A(e) and (f) (Synchronized Reserve)	585 Continued	9.0.0	500	In determining the appropriate amount of the Synchronized Reserve Market Clearing Price (SRMCP) and the credit due to a Generating Market Buyer providing Tier 2 Synch Reserves, PJM calculates the real-time opportunity costs by multiplying the reduction in Tier 2 cleared MW by the positive difference (not the absolute value) between LMP and the offer price. PJM	(e) In determining the Synchronized Reserve Market Clearing Price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the expected Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) ~~the absolute value of~~ the difference between the expected 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 Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when

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					believes that this is the correct way to perform the calculation. The absolute value language was incorrectly inserted into Section 3.2.3A when this section was originally incorporated into the OATT and Operating Agreement in a filing made by PJM on March 20, 2003 in Docket No. RT01-2-006. The language was incorrectly carried over from the provision in Section 3.2.2(d) and (e) concerning the calculation of the Regulation Market Clearing Price. PJM does not calculate the Synch Reserve Market Clearing Price using the absolute value of the difference between LMP and offer price because PJM does not dispatch generators to higher output level for the purpose of providing reserves like it does for Regulation. It is inappropriate to calculate the SRMCP using the absolute value in the calculation, because if LMP was less than the cost at the minimum MW amount of electric energy that a generating resource produces while under economic dispatch, the resource would not incur an opportunity cost by providing reserves because operating at its minimum output point would be economic. Using absolute value is correct with respect to calculating the Regulation Market Clearing Price because generators may have their output raised	the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero. (f) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to 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, times (B) ~~the absolute value of~~ 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 Synchronized Reserve set point for the generation 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. The opportunity costs for a Demand Resource shall be zero.

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					or lowered from a point that would otherwise be economic to provide Regulation. This means that the opportunity cost for providing Regulation as opposed to providing energy may take the form of either, lost revenue in the energy market because the generation resource had to reduce its output below where it was economic (LMP › offer price), or, increased costs when the unit has to raise its output to a point where its cost to operate at that output level is higher than the LMP (offer › LMP). Because the Regulation opportunity cost may be incurred by either raising or lowering the unit's output from its ideal, economic point, the absolute value is appropriate in this case.	
30.	OATT, Attachment K – Appendix Section 3.2, specifically §3.2.3B(f) (Reactive Services)	585 Continued	9.0.0	500	The Reactive Services Lost Opportunity Cost Credits provision was not written to cover the Regulation and Synch Reserve in the same hour. Therefore the provision should be clarified to reflect this possibility. Manual 28 also addresses this issue.	A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is 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 hourly in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where: AG equals the actual hourly integrated output of the unit; 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 hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments; UB equals the unit offer for that unit for which output is increased, determined

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						according to the real time scheduled offer curve on which the unit was operating; URTLMP equals the real time LMP at the unit's bus; and where UB - URTLMP shall not be negative.
31.	OATT, Attachment K – Appendix Section 3.2, specifically §3.2.3B(g) (Reactive Services)	585 Continued	9.0.0	500	Section 3.2.2A(d) does not exist. The correct section reference should be 3.2.2(d).	A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to 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~~A~~(d) and 3.2.3A(f) and further detailed in the PJM Manuals.
32.	OATT, Attachment K – Appendix Section 3.3 Market Sellers, specifically §3.3.1(d) (Spot Market Energy Charges)	586	2.0.0	500	"At that bus" language should be removed to avoid any confusion since spot market calculations are not location specific.	A Market Seller shall be paid for real-time sales of Spot Market Energy to the extent of its hourly net deliveries to the PJM Region of energy in excess of amounts scheduled in the Day-ahead Energy Market from the Market Seller's resources. For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the hourly amounts delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region. The total real-time generation revenues for each Market Seller shall be the sum of its payments determined by the product of (i) the hourly net amount of energy delivered to the PJM Region in excess of the amount scheduled to be delivered in that hour ~~at that bus~~ in the Day-ahead Energy Market from each of the Market Seller's resources, times (ii) the hourly Real-time System Energy Price. To the extent that the energy actually injected in any hour is less than the energy scheduled to be injected ~~at that bus~~ in the Day-ahead Energy Market, the Market Seller shall be debited for the difference at the Real-time System Energy Price at the time of the shortfall times the amount of the shortfall. The total generation revenue for each Market Seller shall be the sum, of the revenues at Day-ahead System Energy Prices determined in accordance with the Day-ahead Energy Market as specified in Section 3.3.1(a) plus the revenues at Real-time System Energy Prices determined as specified herein, net of any debits specified herein for each Market Seller.
33.	OATT, Attachment K – Appendix Section 5.1, specifically §5.1.1 (Transmission Congestion Charge Calculation - Calculation by Office of the Interconnection)	594	2.0.0	500	Section 9.3 does not exist in Attachment K – Appendix.	When the transmission system is operating under constrained conditions, or as necessary to provide third-party transmission provider losses ~~in accordance with Section 9.3~~, the Office of the Interconnection shall calculate Transmission Congestion Charges for each Network Service User, Market Participants in the PJM Interchange Energy Market, and each Transmission Customer.

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34.	OATT, Attachment K – Appendix Section 5.1, specifically §5.1.3(a) Network Service User Calculation) (See also §5.4.3(a) below)	594 Continued	2.0.0	500	The terms "hourly congestion net bill" and "hourly losses net bill" are no longer used in any PJM FERC-accepted agreement or PJM Manual. This term was made obsolete when marginal losses was implemented but this section was not updated completely at that time. Therefore, the terms should be deleted to avoid potential confusion.	Each Network Service User shall be charged for the increased cost of energy incurred by it during each constrained hour to deliver the output of its firm Generation Capacity Resources or other owned or contracted for resources, its firm bilateral purchases, and its non-firm bilateral purchases as to which it has elected to pay Transmission Congestion Charges. ~~The Transmission Congestion Charge for deliveries from each such source shall be the Network Service User's hourly congestion net bill.~~
35.	OATT, Attachment K – Appendix, §5.1.4 (Transmission Customer Calculation) (See also §5.4.4 and §5.4.4A below)	594 Continued	2.0.0	500	This revision is necessary to clarify that Network Imports and eSchedules Internal Bilateral Transactions are also charged Explicit Congestion and Explicit Losses. These changes should have been made when marginal losses were implemented but this section was not updated completely at that time. Additionally, the reference to "Real-time deviations from the Point-to-Point Transmission Service scheduled in the Day-ahead Energy Market shall be determined by the lesser of the real-time injection or withdrawal associated with such transmission service" may have been related to old losses paid-in-kind language that PJM used to have in the OATT. For that reason, it should have been removed with the Marginal Losses implementation.	**5.1.4 Transmission Customer Calculation.** Each Transmission Customer using Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), each Network Customer, and each Transmission Customer using Non-Firm Point-to-Point Transmission Service (as defined in the PJM Tariff) that has elected to pay Transmission Congestion Charges, shall be charged for the increased cost of energy during constrained hours for the delivery of energy using such ~~Point-to-Point~~ Transmission Service. Except as specified in this subsection, a Transmission Congestion Charge shall be assessed for transmission use scheduled in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region and the Day-ahead Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. Transmission Congestion Charges shall be assessed for real-time transmission use in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. A Transmission Customer shall be paid for Transmission Congestion Charges for real-time transmission use falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. ~~Real-time deviations from the Point-to-Point Transmission Service scheduled in the Day-ahead Energy Market shall be determined by the lesser of the real-time injection or withdrawal associated with such transmission service.~~

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						5.1.4A Transaction Calculation. Each Market Participant entering into transactions in the PJM Interchange Energy Markets shall be charged for the increased cost of energy during constrained hours for the delivery of energy on the scheduled path. Except as specified in this subsection, a Transmission Congestion Charge shall be assessed for cleared MWh in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Congestion Price at the sink point and the Day-ahead Congestion Price at the source point. Transmission Congestion Charges shall be assessed for real-time cleared MWh in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Congestion Price at the sink point and the Real-time Congestion Price at the source point. Such Market Participant shall be paid for Transmission Congestion Charges for real-time cleared MWh falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Congestion Price at the sink point and the Real-time Congestion Price at the source point.
36.	OATT, Attachment K – Appendix Section 5.1, specifically §5.1.7 (Total Transmission Congestion Charges)	594 Continued	2.0.0	500	The definition of Total Transmission Congestion Charges for allocation of credits should be clarified by way of a reference to the PJM Manuals since Manual 28, Section 7.4.2 is where the detail of all components of Total PJM Congestion Charges is specified.	The total Transmission Congestion Charges collected by PJMSettlement each hour will be the aggregate net amounts determined as specified in ~~this Schedule~~the PJM Manuals. PJMSettlement shall collect Transmission Congestion Charges for each hour the transmission system operates under constrained conditions.
37.	OATT, Attachment K – Appendix Section 5.4, specifically §5.4.1 (Transmission Loss Charge Calculation - Calculation by Office of the Interconnection)	597	3.0.0	500	Suggesting clarification for accuracy.	The Office of the Interconnection shall calculate Transmission Loss Charges for each Network Service User, Market Participant in the PJM Interchange Energy Market, and each Transmission Customer.

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38.	OATT, Attachment K – Appendix Section 5.4, specifically §5.4.3(a) (Network Service User Calculation) (See also §5.1.3(a) above)	597 Continued	3.0.0	500	The terms "hourly congestion net bill" and "hourly losses net bill" are no longer used in any PJM FERC-accepted agreement or PJM Manual. This term was made obsolete when marginal losses was implemented but this section was not updated completely at that time. Therefore, the terms should be deleted to avoid potential confusion.	Each Network Service User shall be charged for the increased cost of transmission losses to deliver the output of its firm Capacity Resources or other owned or contracted for resources, its firm bilateral purchases, and its non-firm bilateral purchases. ~~The Transmission Loss Charge for deliveries from each such source shall be the Network Service User's hourly losses net bill.~~
39.	OATT, Attachment K – Appendix, §5.4.4 and 5.4.4A (Transmission Customer Calculation) (See also §5.1.4 and 5.1.4A above)	597 Continued	3.0.0	500	This revision is necessary to clarify that Network Imports and eSchedules Internal Bilateral Transactions are also charged Explicit Congestion and Explicit Losses. These changes should have been made when marginal losses were implemented but this section was not updated completely at that time. Additionally, the reference to "Real-time deviations from the Point-to-Point Transmission Service scheduled in the Day-ahead Energy Market shall be determined by the lesser of the real-time injection or withdrawal associated with such transmission service" may have been related to old losses paid-in-kind language that PJM used to have in the OATT. For that reason, it should have been removed with the Marginal Losses implementation.	**5.4.4 Transmission Customer Calculation.** Each Transmission Customer using Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), each Network Customer, and each Transmission Customer using Non-Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), shall be charged for the increased cost of transmission losses for the delivery of energy using ~~Point-to-Point~~such Transmission Service. Except as specified in this subsection, a Transmission Loss Charge shall be assessed for transmission use scheduled in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Loss Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region and the Day-ahead Loss Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. Transmission Loss Charges shall be assessed for real-time transmission use in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Loss Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Loss Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. A Transmission Customer shall be paid for Transmission Loss Charges for real-time transmission use falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Loss Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Loss Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region or the source Interface Pricing Point at the boundary of the PJM Region. ~~Real-time deviations from the Point-to-Point Transmission Service scheduled in the Day-ahead Energy Market shall be determined by the lesser of the real-time injection or withdrawal associated with such transmission service.~~

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						5.4.4A Transaction Calculation. Each Market Participant entering into transactions in the PJM Interchange Energy Market shall be charged for the increased cost of transmission losses on the scheduled path. Except as specified in this subsection, a Transmission Loss Charge shall be assessed for cleared MWh in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Loss Price at the sink point and the Day-ahead Loss Price at the source point. Transmission Loss Charges shall be assessed for real-time cleared MWh in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Loss Price at the sink point and the Real-time Loss Price at the source point. Such Market Participant shall be paid for Transmission Loss Charges for real-time cleared MWh falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Loss Price at the sink point and the Real-time Loss Price at the source point.
40.	OATT, Attachment M – Appendix Section, specifically §II.F (Development of Inputs for Prospective Mitigation – Mitigation of Offers from Planned Generation Capacity Resources)	946	3.0.0	500	Correct grammatical error/typographical error originating in PJM's Order 719 filing in Docket No. ER09-1063 on Original Sheet No. 453O.	Pursuant to Section 6.5 of Attachment DD, the Market Monitoring Unit shall notify each Capacity Market Seller whose Sell Offer ~~that its Sell Offer~~ has been determined to be excessive.
41.	OATT, Attachment M – Appendix Section, specifically §VIII (Data collection and verification)	946 Continued	3.0.0	500	Fuel data to support Black Start Service was previously provided to PJM's internal Market Monitoring Unit per the terms of the eFuel Manual. The eFuel Manual has been retired because fuel data is now provided to PJM's external, independent market monitor (IMM) per the requirements of Monitoring Analytics, LLC. Therefore,	The Market Monitoring Unit shall gather and keep confidential detailed data on the procurement and usage of fuel to produce electric power transmitted in the PJM Region in order to assist the performance of its duties under Attachment M. To achieve this objective, the Market Monitoring Unit shall maintain on its website a mechanism that allows Members to conveniently and confidentially submit such data and develop a manual in consultation with stakeholders that describes the nature of and procedure for collecting data. Members of PJM owning a Generating unit that is located in the PJM Region (including dynamically scheduled units), or is included in a PJM Black Start Service plan, committed as a Generation Capacity Resource for the current or future Delivery Year, or otherwise subject to a commitment to provide service to PJM, shall provide data to

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					the provision should be updated to reflect that the manner in which fuel data is to be provided to PJM's IMM is not prescribed in a PJM Manual.	the Market Monitoring Unit ~~in the manner prescribed in the PJM Manuals~~.
42.	OATT, Attachment DD, §2.4 (Definitions – Base Offer Segment)	1139	9.0.0	500	Revised reference to "existing Generation Capacity Resource" to the defined term "Existing Generation Capacity Resource."	"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 Eexisting 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.
43.	OATT, Attachment DD, §2.9A (Def'n of Capacity Export Transmission Customer	1139 Continued	9.0.0	500	Delete erroneous reference to Section 5.6.6(d) of Att. DD, which should have been corrected in filing PJM submitted on December 2, 2010 in Docket No. ER11-2287-000.	"Capacity Export Transmission Customer" shall mean a customer taking point to point transmission service under Part II of this Tariff to export capacity from a generation resource located in the PJM Region that ~~is delisted from Capacity Resource status~~ has qualified for an exception to the RPM must-offer requirement as described in section 6.6(g)~~5.6.6(d)~~.
44.	OATT, Attachment DD, §5.8(e) (Submission of Sell Offers and Buy Bids)	1151	3.0.0	500	While the eRPM system is available during the open window, if PJM experiences a problem with this system it should have the ability to communicate with Market Participants an alternative means that they can use to submit or withdraw Sell Offers or Buy Bids. Rather than specifying this alternative in a PJM Manual, PJM's practice would be to send a notice via email (most likely to the RPM Hotline) or call Market Participants to advise where they should email or fax the	Sell Offers or Buy Bids shall be submitted or withdrawn via the Internet site designated by the Office of the Interconnection; provided, however, that if the Internet site cannot be accessed at any time during the period specified for the applicable auction, a Sell Offer or Buy Bid may be submitted or withdrawn by electronic mail transmitted to the e-mail address~~,~~ or faxed to the fax number~~,~~ specified by the Office of the Interconnection ~~in the PJM Manuals~~.

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					information. And while it is unlikely that PJM would choose the fax option, if email is unavailable for some reason, the fax capability should be retained. However, PJM should have the flexibility to communicate with Market Participants directly with the appropriate contact information for that particular day rather than relying on a dated email address or fax number that is in a PJM Manual.	
45.	OATT, Attachment DD Section 5.15, specifically §5.15(a) (Capacity Transfer Rights)	1159	1.0.0	500	With the implementation of the Incremental Auction redesign in 2010, the tariff language needed to be updated to more clearly and accurately describe how LDA CTR MWs and final Zonal CTR Settlement Rates are re-calculated and updated after each IA .Existing language did not adjust CTR MW quantity to reflect capacity import of Incremental Auctions nor did it reflect the updating of the CTR Settlement Rate after each IA.	(a) To recognize the value of Import Capability and provide a partial offset to potential Locational Price Adders that may be determined for an LDA (as to any Zone that encompasses two or more LDAs, the term "LDA" as used herein shall refer to such Zone, rather than to the LDAs it encompasses), the Office of the Interconnection shall allocate Capacity Transfer Rights to each LSE serving load in such LDA pro rata based on such LSE's Daily Unforced Capacity Obligation in such LDA. The total megawatts of Capacity Transfer Rights available for allocation shall equal the megawatts of Unforced Capacity imported into such LDA ~~as~~ determined ~~in~~ based on the results of the Base Residual Auction and Incremental Auctions ("Capacity Imported"), less any megawatts of CETL increase into such LDA attributable to Qualifying Transmission Upgrades cleared in an RPM Auction and any Incremental Capacity Transfer Rights into such LDA allocated pursuant to section 5.16 (but not less than zero), and shall be subject to change in subsequent Delivery Years as a result of changes in the quantity of such Capacity Imported into such LDA. Each change in an LSE's Daily Unforced Capacity Obligation during a Delivery Year shall result in a corresponding change in the Capacity Transfer Rights allocated to such LSE. (b) ~~For purposes of any Base Residual Auction in an LDA~~ For LDAs ~~that~~ in which the RPM Auctions for the Delivery Year result~~ed~~ in a positive average weighted Locational Price Adder with respect to the immediate higher level LDA, the holder of the Capacity Transfer Rights in such LDA shall receive a payment during the Delivery Year equal to (i) the average weighted Locational Price Adder for such LDA determined with respect to the immediate higher level LDA as a result of ~~such~~ all RPM ~~a~~Auctions for such Delivery Year ~~for such LDA minus the Locational Price Adder for the LDA from which Unforced Capacity is imported to determine the Capacity Transfer Right~~, multiplied by (ii) the megawatt quantity of the Capacity Transfer Right allocated to such LSE in such LDA. ~~(c) For purposes of any Incremental Auction in such LDA that results in a positive Locational~~

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						~~Price Adder, the holder of a Capacity Transfer Right shall receive a payment during the Delivery Year equal to the difference between the charges for the incremental Daily Unforced Capacity Obligation and the credits to be paid to the incremental Unforced Capacity cleared in the LDA plus incremental Unforced Capacity imported.~~ ~~(d) Where an LDA is entirely contained within another LDA, a portion of the larger LDA Capacity Transfer Rights will be allocated to the smaller LDA, based on the smaller LDA's proportion of the larger zone's unforced capacity obligation. LDA remaining for determination of further credits will be reduced by the allocation of credits attributable to Capacity Imported into the larger LDA.~~ (~~e~~c) Capacity Transfer Rights shall be transferable. A purchaser of Capacity Transfer Rights from the original party allocated such rights shall receive any payments due under this section or section 5.16, provided the seller and purchaser of such rights timely notify the Office of the Interconnection of such purchase, in accordance with procedures specified in the PJM manuals.
46.	OATT, Attachment DD, §5.16(b) (Incremental Capacity Transfer Rights)	1160	1.0.0	500	With the implementation of the Incremental Auction redesign in 2010, the tariff language needed to be updated to more clearly and accurately describe how ICTR Settlement Rates are re-calculated and updated after each IA .	For LDAs in which ~~any Base Residual or Incremental~~ the RPM Auctions for such Delivery Year that result~~s~~ in a positive average weighted Locational Price Adder ~~for such LDA~~ with respect to the immediate higher level LDA, the holder of an Incremental Capacity Transfer Right into such LDA shall receive a payment equal to the average weighted Locational Price Adder for the LDA into which the associated facility or upgrade increased Import Capability~~, minus the Locational Price Adder for the LDA from which the Import Capability increase was measured~~, multiplied by the megawatt quantity of the Incremental Capacity Transfer Right allocated to such Interconnection Customer.
47.	OATT, Attachment DD Section 6, specifically §6.3(a) (Market Structure Tests)	1161	5.0.0	500	Revised reference to "existing Generation Capacity Resource" to the defined term "Existing Generation Capacity Resource."	The Market Monitoring Unit shall apply the Preliminary Market Structure Screen pursuant to section II.D of Attachment M - Appendix. Potential Capacity Market Sellers owning or controlling any Eexisting Generation Capacity Resources in the PJM Region shall be required to provide to the Market Monitoring Unit the additional information specified in section II.D of Attachment M - Appendix if such Generation Capacity is located in an LDA, "Unconstrained LDA Group" (as defined in Attachment M - Appendix), or the entire PJM Region that fails the Preliminary Market Structure Screen, as applied pursuant to section II.D below.
48.	OATT, Attachment DD Section 6, specifically §6.4(a) and (b) (Market Seller Offer Caps)	1161 Continued	5.0.0	500	Revision to change "installed capacity" to "unforced capacity" is needed for consistency. Correcting references to "existing Generation Capacity Resource" to the	(a) The Market Seller Offer Cap, stated in dollars per MW-day of unforced~~installed~~ capacity, applicable to price-quantity offers within the Base Offer Segment for an ~~e~~Existing Generation Capacity Resource shall be the Avoidable Cost Rate for such resource, less the Projected PJM Market Revenues for such resource, stated in dollars per MW of unforced capacity. During the first three Delivery Years of the Transition Period, the Market Seller Offer Cap shall be increased for Sell Offers submitted by eligible Capacity Market Sellers in any Unconstrained LDA Group by the Transition

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					defined term "Existing Generation Capacity Resource."	Adder set forth in section 17.5 of this Attachment. The Market Seller Offer Cap for an eExisting Generation Capacity Resource shall be the Opportunity Cost for such resource, if applicable, as determined in accordance with section 6.7. Nothing herein shall preclude any Capacity Market Seller and the Market Monitoring Unit from agreeing to, nor require either such entity to agree to, an alternative market seller offer cap determined on a mutually agreeable basis. Any such alternative offer cap shall be filed with the Commission for its approval. This provision is duplicated in section II.E.3 of Attachment M- Appendix. (b) For each Eexisting Generation Capacity Resource, a potential Capacity Market Seller must timely provide to the Market Monitoring Unit data and documentation required under section 6.6 to establish the level of the Market Seller Offer Cap applicable to each resource. The Capacity Market Seller must promptly address any concerns identified by the Market Monitoring Unit regarding the data and documentation provided, review the proposed Market Seller Offer Cap, and attempt to reach agreement with the Market Monitoring Unit on the level of the Market Seller Offer Cap.
49.	OATT, Attachment DD Section 6, specifically §6.7(d)(ii) (Data Submission)	1161 Continued	5.0.0	500	Correct reference to how the Market Seller Offer Cap is calculated.	In order for costs to qualify for inclusion in the Market Seller Offer Cap, the Capacity Market Seller must provide to the Market Monitoring Unit relevant cost data concerning each data item specified as set forth in section 6. If cost data is not available at the time of submission for the time periods specified in section 6.8, costs may be estimated for such period based on the most recent data available, with an explanation of and basis for the estimate used. Based on the data and calculations submitted by the Capacity Market Sellers for each existing generation resource and the formulas specified below, the Market Monitoring Unit shall calculate the Market Seller Offer Cap for each such resource, and notify the Capacity Market Seller one month prior to the auction of its determination. i. Avoidable Cost Rate: The Avoidable Cost Rate for an existing generation resource shall be determined using the formula below and applied to the unit's Base Offer Segment. ii. Opportunity Cost: Opportunity Cost shall be the documented price available to an existing generation resource in a market external to PJM. In the event that the total MW of existing generation resources submitting opportunity cost offers in any auction for a Delivery Year exceeds the firm export capability of the PJM system for such Delivery Year, or the capability of external markets to import capacity in such year, the Office of the Interconnection will accept such offers on a competitive basis. PJM will construct a supply curve of opportunity cost offers, ordered by opportunity cost, and accept such offers to export starting with the highest opportunity cost, until the maximum level of such exports is reached. The maximum level of such exports is the lesser of the Office of the Interconnection's ability to permit firm exports or the ability of the importing area(s) to accept firm imports or imports of capacity, taking account of relevant export limitations by location.

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						If, as a result, an opportunity cost offer is not accepted from an existing generation resource, the Market Seller Offer Cap applicable to Sell Offers relying on such generation resource shall be the Avoidable Cost Rate less the Projected Market Revenues for such resource (as defined in Section 6.4). The default Avoidable Cost Rate shall be the one year mothball Avoidable Cost Rate set forth in the tables in section 6.7(c) above unless Capacity Market Seller satisfies the criteria delineated in section 6.7(~~ee~~) below.
50.	OATT, Attachment DD Section 6, specifically §6.8(a) (ACR Values)	1161 Continued	5.0.0	500	When PJM submitted RPM settlement filing on December 12, 2008 in Docket No. ER09-412-000, it inadvertently neglected to change a reference to the "16 Plus" category of capital recovery factors to the "25 Plus" category when it eliminated the "16 Plus" category in the filing. The change should now be made to maintain consistency with the revisions to the capital recovery factor table and to avoid confusion. Additionally, outdated language regarding sell offers submitted for Delivery Years that have long since passed should be deleted. Revised reference to "existing Generation Capacity Resource" to the defined term "Existing Generation Capacity Resource." Finally, incorrect references to the "40 Year Plus Alternative" should be corrected to read "40 Plus Alternative Option" which is the correct title of the category.	Capital Expenditures and Project Investment For any given Project Investment, a Capacity Market Seller may make a one-time election to recover such investment using: (i) the highest CRF and associated recovery schedule to which it is entitled; or (ii) the next highest CRF and associated recovery schedule. For these purposes, the CRF and recovery schedule for the ~~16~~ 25 Plus category is the next highest CRF and recovery schedule for both the Mandatory CapEx and the 40 Plus Alternative categories. The Capacity Market Seller using the above table must provide the Market Monitoring Unit with information, identifying and supporting such election, including but not limited to the age of the unit, the amount of the Project Investment, the purpose of the investment, evidence of corporate commitment (e.g., an SEC filing, a press release, or a letter from a duly authorized corporate officer indicating intent to make such investment), and detailed information concerning the governmental requirement (if applicable). Absent other written notification, such election shall be deemed based on the CRF such Seller employs for the first Sell Offer reflecting recovery of any portion of such Project Investment. ~~A Sell Offer submitted in the BRA for either or both of the 2007-2008 and 2008-2009 Delivery Years for which the "16 Plus" CRF and recovery schedule is selected may not exceed an offer price equal to the then-current Net CONE (on an unforced-equivalent basis).~~ For any resource using the CRF and associated recovery schedule from the CRF table that set the Capacity Resource Clearing Price in any Delivery Year, such Capacity Market Seller must also provide to the Market Monitoring Unit, for informational purposes only, evidence of the actual expenditure of the Project Investment, when such information becomes available. If the project associated with a Project Investment that was included in a Sell Offer using a CRF and associated recovery schedule from the above table has not entered into commercial operation prior to the end of the relevant Delivery Year, and the resource's Sell Offer sets the clearing price for the relevant LDA, the Capacity Market Seller shall be required to elect to either (i) pay a charge that is equal to the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the APIR component of the Avoidable Cost Rate, this difference to be multiplied by the cleared MW volume from such Resource

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						("rebate payment"); (ii) hold such rebate payment in escrow, to be released to the Capacity Market Seller in the event that the project enters into commercial operation during the subsequent Delivery Year or rebated to LSEs in the relevant LDA if the project has not entered into commercial operation during the subsequent Delivery Year; or (iii) make a reasonable investment in the amount of the PI in other Eexisting Generation Capacity Resources owned or controlled by the Capacity Market Seller or its Affiliates in the relevant LDA. The revenue from such rebate payments shall be allocated pro rata to LSEs in the relevant LDA(s) that were charged a Locational Reliability Charge for such Delivery Year, based on their Daily Unforced Capacity Obligation in the relevant LDA(s). If the Sell Offer from the Generation Capacity Resource did not set the Capacity Resource Clearing Price in the relevant LDA, no alternative investment or rebate payment is required. If the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the APIR amount does not exceed the greater of $10 per MW-day or a 10% increase in the clearing price, no alternative investment or rebate payment is required. . . . 40 ~~Year~~ Plus Alternative Option The 40 Plus Alternative CRF and recovery schedule is an option available, beginning in the third BRA (Delivery Year 2009-10), for a resource that is a gas- or oil-fired resource that began commercial operation no less than 40 years prior to the conduct of the relevant BRA (excluding, however, any resource in any Delivery Year for which the resource is receiving a payment under Part V of the PJM Tariff. Generation Capacity Resources electing this 40 Plus Alternative CRF shall be treated as At Risk Generation for purposes of the sensitivity runs in the RTEP process). Resources electing the 40 ~~Year~~ Plus Alternative ~~O~~option will be modeled in the RTEP process as "at-risk" at the end of the one-year amortization period.
51.	OATT, Attachment DD Section 8, specifically §8.1(c) (Capacity Resource Deficiency Charge – External Generation Resource)	1163	3.0.0	500	Revised reference to "existing Generation Capacity Resource" to the defined term "Existing Generation Capacity Resource."	External Generation Resource – Such Capacity Resource is an Eexisting Generation Capacity Resource that is located outside of the PJM Control Area and arrangements for the firm delivery of the output of such resource to the interface with the PJM Region are not in place for such resource prior to the start of the Delivery Year;
52.	OATT, Attachment DD	1169	1.0.0	500	Correction needed to clarify that the	Following an Emergency, the compliance during the period of such Emergency with the instructions

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	Section 13, specifically §13.1 (Application of the Emergency Procedure Charge)				reference to "Market Seller" should be a reference to "Capacity Market Seller" consistent with other references in the section.	of the Office of the Interconnection of: (a) each Capacity Market Seller that committed Capacity Resources, and each Locational UCAP Seller that sold Locational UCAP, for such period; and (b) each ILR Provider responsible for ILR certified for such period, shall be evaluated as recommended by the Markets and Reliability Committee and directed by the PJM Board. If, based on such evaluation, it is determined that a Capacity Market Seller, Locational UCAP Seller, or ILR Provider refused to comply with, or otherwise failed to employ its best efforts to comply with, the instructions of the Office of the Interconnection to implement PJM emergency procedures, then such Capacity Market Seller, Locational UCAP Seller, or ILR Provider shall pay an Emergency Procedure Charge.
53.	OATT, Attachment DD §15 (Coordination with Economic Planning Process)	1171	1.0.0	500	Schedule 12 of the Tariff already specifies how costs for upgrades are allocated. Therefore, to avoid potential conflicting language, the provision should be revised to cross reference Schedule 12 of the Tariff.	Following each Base Residual Auction, the Office of the Interconnection shall review each LDA that has a Locational Price Adder to determine if Planned Generation Capacity Resources, Planned Demand Resources, or Qualifying Transmission Upgrades submitted Sell Offers that cleared in such auction. If a Locational Price Adder results from the clearing of an LDA for two consecutive Base Residual Auctions, and no such planned resources or upgrades clear in such auctions for such LDA, then the Office of the Interconnection shall evaluate in the RTEP process the costs and benefits of a transmission upgrade that would reduce to zero the Locational Price Adder for such LDA. Such evaluation will compare the cost of the upgrade over ten years against the value of elimination of the Locational Price Adder over such period. If such upgrade is found to be feasible and beneficial, it shall be included in the RTEP as soon as practicable. The annual costs of such upgrade shall be allocated ~~to all LSEs serving load in such LDA, pro rata based on such loads~~as specified in Schedule 12 of the Tariff and Schedule 6 of the Operating Agreement.
PJM Operating Agreement						
54.	OA Schedule 1, Section 1.10, specifically §1.10.1A(h) (Scheduling - General)	770	7.0.0	500	Day-ahead scheduled loads are not posted on OASIS but are posted in eMKT.	The Office of the Interconnection shall post ~~on the PJM Open Access Same-time Information System~~ 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.
55.	OA Schedule 1, Section 1.10, specifically §1.10.5(b) (Scheduling – External Resources)	770 Continued	7.0.0	500	PJM's eMKT does not support multiple offers from an aggregated external resource. While the market is open, anything about offers can be changed. Once an offer is submitted in eMKT and the market closes, it can't be withdrawn.	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. ~~If a Market Seller submits more than one offer on an aggregated resource basis, the withdrawal of any such offer shall be deemed a withdrawal of all higher priced offers for the same period.~~

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56.	OA Schedule 1, Section 1.10, specifically §1.10.6(a) (Scheduling – External Market Buyers)	770 Continued	7.0.0	500	This calculation should not be limited to load busses. Revision to make bus reference general so as to include interface busses. In addition, Day-ahead and Real-time pricing can both be applied in the same hour and Market Buyers can be Market Sellers at the same time but focus should be on load busses.	Deliveries to an External Market Buyer not subject to dynamic dispatch by the Office of the Interconnection shall be delivered on a block loaded basis to the ~~load~~ 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) ~~or credited~~ at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing ~~load~~bus or buses.
57.	OA Schedule 1, Section 1.10, specifically §1.10.8(b), (c) and (d) (Scheduling – Office of the Interconnection Responsibilities)	770 Continued	7.0.0	500	PJM notifies the market of significant changes that could affect market decisions. However the specific information listed in subsection (c) is not provided. The language that PJM seeks to delete from subsection (c) was formerly also included in subsection (b), which was deleted in a filing submitted on March 10, 2000 in Docket No. ER00-1849-000, the "two settlement system filing" that established PJM's Day-ahead Energy Market. The transmittal letter for this filing doesn't explain why the language was removed from subsection (b) but not from subsection (c). PJM believes the day-ahead market mooted the need for an initial estimate of congestion and that the same logic would have applied all along to the LMP-based real-time market and mooted the need for a revised estimate of congestion as well. Thus, the language should have been removed from subsection (c) in that same 2000 filing.	(b) Not earlier~~later~~ than 4:00 p.m. of the day before each Operating Day, or such other~~earlier~~ 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. (c) Following posting of the information specified in Section 1.10.8(b), 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. ~~The Office of the Interconnection shall post on the PJM Open Access Same-time Information System at times specified in the PJM Manuals a revised forecast of the location and duration of any expected transmission congestion, and of the range of differences in Locational Marginal Prices between major subareas of the PJM Region expected to result from such transmission congestion.~~ (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 offer that set 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 offer that set the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Section 3.3A of this Schedule.

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					The removal of the referenced language will not alleviate PJM's obligation to post helpful planning information. Operating Agreement, Schedule 6, Subsection (f) states: "The Office of the Interconnection will also provide access through the PJM website, to the planning criteria and assumptions used by the Transmission Owners for the development of the current Local Plan." Subsection (e) states that FERC Form No. 715 material will be posted on the PJM website.	
58.	OA Schedule 1, Section 1.11 (Dispatch), specifically §1.11.4(b) (Regulation)	771	2.0.0	500	There is a conflict in the provision and the design of the software program that determines how resources should be dispatched with respect to how Regulation offer ties are broken. Software provides that for price-tied regulation offers are dispatched in order of their MW values. The tie-breaking is implemented in the optimization software. Therefore, the provision should be revised to delete the incorrect language.	The Office of the Interconnection shall obtain Regulation service from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Demand Resources as needed to meet Regulation Zone requirements not otherwise satisfied by the Market Buyers. Generation resources or Demand Resources offering to sell Regulation shall be selected to provide Regulation on the basis of each generation resource's and Demand Resource's regulation offer and the estimated opportunity cost of a resource providing regulation and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Regulation, and other ancillary services. Estimated opportunity costs for generation resources shall be determined by the Office of the Interconnection on the basis of the expected value of the energy sales that would be foregone or uneconomic energy that would be produced by the resource in order to provide Regulation, in accordance with procedures specified in the PJM Manuals. Estimated opportunity costs for Demand Resources will be zero. ~~If the Office of the Interconnection is not able to distinguish resources offering Regulation on the basis of their regulation offers and estimated opportunity costs, resources shall be selected on the basis of the quality of Regulation provided by the resource as determined by tests administered by the Office of the Interconnection.~~
59.	OA Schedule 1, Section 3.2, specifically §3.2.1(d) (Spot Market Energy Charges)	784	9.0.0	500	Provision does not allow for Internal Market Buyers to have amounts scheduled in the Day-ahead Energy Market. Clean up language to delete "the External" replace with "such."	At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the total amount of net hourly PJM Interchange for each Market Buyer, including Generating Market Buyers, in accordance with the PJM Manuals. For Internal Market Buyers that are Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall include determination of the net energy flows from: (i) tie lines; (ii) any generation resource the output of which is controlled by the Market Buyer but delivered to it over another entity's Transmission Facilities; (iii) any generation resource the output of which is controlled by another entity but which is directly interconnected with the Market Buyer's transmission system; (iv) deliveries pursuant to bilateral

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						energy sales; (v) receipts pursuant to bilateral energy purchases; and (vi) an adjustment to account for the day-ahead PJM Interchange, calculated as the difference between scheduled withdrawals and injections by that Market Buyer in the Day-ahead Energy Market. For External Market Buyers and Internal Market Buyers that are not Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall determine the energy scheduled hourly for delivery to the Market Buyer net of the amounts scheduled by such ~~the External~~ Market Buyer in the Day-ahead Energy Market.
60.	OA Schedule 1, Section 3.2, specifically §3.2.3(a) (Operating Reserves)	784 Continued	9.0.0	500	There is no Section 3.2.A.01. The correct section reference is 3.2.3A.01.	A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the prices offered 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 Section 3.2.3A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, 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 Scheduling Reserves Requirement.
61.	OA Schedule 1, Section 3.2, specifically §3.2.3(e) (Operating Reserves)	784 Continued	9.0.0	500	PJM doesn't calculate operating reserve credits separately for units committed solely for Synch Reserves. Therefore, the language indicating to the contrary should be deleted. A "period" can be one hour or a range of hours. The reference to "period" in the referenced section is incorrect because Synch Reserve credits are netted against Operating Reserve credits on an hourly basis, not by period. Thus, the reference to "period" in the section should be changed to "hour." Additionally, after PJM implemented segmented make whole payments, the reference to contiguous hours is no longer accurate. Netting is done only on an hourly basis now. Therefore, the	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, ~~and that is not committed solely for the purpose of providing Synchronized Reserve.~~ 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 or minimum run time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or minimum run time (minimum down time for Demand 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 (minimum down time for Demand Resources) and Segment 2 will include the remainder of the contiguous hours 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. . . . Synchronized Reserve and Day-ahead Scheduling Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding hour(s) in which the Synchronized Reserve and Day-ahead Scheduling Reserve credits

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					reference to contiguous hours must e deleted.	accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each hour~~period~~ the unit operates in condensing and generation mode ~~for one or more contiguous hours~~.
62.	OA Schedule 1, Section 3.2, specifically §3.2.3(f) (Operating Reserves)	784 Continued	9.0.0	500	The Operating Reserve Lost Opportunity Cost Credits provision was not written to cover the Regulation and Synch Reserve in the same hour. Therefore the provision should be clarified to reflect this possibility. Manual 28 also addresses this issue.	A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool scheduled (or self-scheduled, if operating according to 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 hourly integrated, 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 hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where: 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 hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments; AG equals the actual hourly integrated output of the unit; URTLMP equals the real time LMP at the unit's bus; UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and where URTLMP - UB shall not be negative.
63.	OA Schedule 1, Section 3.2, specifically §3.2.3(f-2) (Operating Reserves)	784 Continued	9.0.0	500	Section 3.2.2A(d) does not exist. The correct section reference should be 3.2.2(d).	A Market Seller's hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to 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

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						sections 3.2.2~~A~~(d) and 3.2.3A(f) and further detailed in the PJM Manuals.
64.	OA Schedule 1, Section 3.2, specifically §3.2.3(j) and (k) (Operating Reserves)	784 Continued	9.0.0	500	Section 3.2.3(j) is not consistent with Section 3.2.3(k). Operating Reserve Synchronous Condensing Credits are no longer determined separately by Control Zone. Rather, Section 3.2.3(k) indicates that the allocation for all credits go to all load and exports in the PJM region.	(j) The sum of the foregoing credits as specified in Section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for ~~each Control Zone of~~ the PJM Region ~~based on the Control Zone to which the resource was synchronized to provide synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation~~. (k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized 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 (net of operating Behind The Meter Generation, but not to be less than zero) 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 dynamically scheduled to load outside ~~such Control Zone~~the PJM Region pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.
65.	OA Schedule 1, Section 3.2, specifically §3.2.3(o) (Operating Reserves)	784 Continued	9.0.0	500	In some scenarios the UDS Case is unavailable, the ramp-limited desired MW from markets is false and the bad limits indicator is also false. Manual 28 specifies that in such case PJM must use UDS LMP desired MW in the referenced calculation of Operating Reserves The provision should be revised to specify how PJM makes its calculation. The bad limits indicator is in the deviation report. When it is false, it reflects real-time limits as being more restrictive than day-ahead limits, and can raise the economic minimum and	To determine if a 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 UDS Basepoint or the actual output and ramp-limited desired MW value. The % off dispatch and MW off dispatch will be a time-weighted average over the course of an hour. If the UDS Basepoint 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 UDS LMP Desired MW.

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					lower the economic maximum.	
66.	OA Schedule 1, Section 3.2, specifically §3.2.3A(e) and (f) (Synchronized Reserve)	784 Continued	9.0.0	500	In determining the appropriate amount of the Synchronized Reserve Market Clearing Price (SRMCP) and the credit due to a Generating Market Buyer providing Tier 2 Synch Reserves, PJM calculates the real-time opportunity costs by multiplying the reduction in Tier 2 cleared MW by the positive difference (not the absolute value) between LMP and the offer price. PJM believes that this is the correct way to perform the calculation. The absolute value language was incorrectly inserted into Section 3.2.3A when this section was originally incorporated into the OATT and Operating Agreement in a filing made by PJM on March 20, 2003 in Docket No. RT01-2-006. The language was incorrectly carried over from the provision in Section 3.2.2(d) and (e) concerning the calculation of the Regulation Market Clearing Price. PJM does not calculate the Synch Reserve Market Clearing Price using the absolute value of the difference between LMP and offer price because PJM does not dispatch generators to higher output level for the purpose of providing reserves like it does for Regulation. It is inappropriate to calculate the SRMCP using the absolute value in the calculation, because if LMP was less than the cost at the minimum MW	(e) In determining the Synchronized Reserve Market Clearing Price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the expected Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) ~~the absolute value of~~ the difference between the expected 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 Synchronized Reserve set 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. The opportunity costs for a Demand Resource shall be zero. (f) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to 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, times (B) ~~the absolute value of~~ 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 Synchronized Reserve set point for the generation 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. The opportunity costs for a Demand Resource shall be zero.

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					amount of electric energy that a generating resource produces while under economic dispatch, the resource would not incur an opportunity cost by providing reserves because operating at its minimum output point would be economic. Using absolute value is correct with respect to calculating the Regulation Market Clearing Price because generators may have their output raised or lowered from a point that would otherwise be economic to provide Regulation. This means that the opportunity cost for providing Regulation as opposed to providing energy may take the form of either, lost revenue in the energy market because the generation resource had to reduce its output below where it was economic (LMP › offer price), or, increased costs when the unit has to raise its output to a point where its cost to operate at that output level is higher than the LMP (offer › LMP). Because the Regulation opportunity cost may be incurred by either raising or lowering the unit's output from its ideal, economic point, the absolute value is appropriate in this case.	
67.	OA Schedule 1, Section 3.2, specifically §3.2.3B(f) (Reactive Services)	784 Continued	9.0.0	500	The Reactive Services Lost Opportunity Cost Credits provision was not written to cover the Regulation and Synch Reserve in the same hour. Therefore the provision should be clarified to reflect	A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is 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

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					this possibility. Manual 28 also addresses this issue.	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 hourly in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where: AG equals the actual hourly integrated output of the unit; 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 hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments; UB equals the unit offer for that unit for which output is increased, determined according to the real time scheduled offer curve on which the unit was operating; URTLMP equals the real time LMP at the unit's bus; and where UB - URTLMP shall not be negative.
68.	OA Schedule 1, Section 3.2, specifically §3.2.3B(g) (Reactive Services)	784 Continued	9.0.0	500	Section 3.2.2A(d) does not exist. The correct section reference should be 3.2.2(d).	A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to 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~~A~~(d) and 3.2.3A(f) and further detailed in the PJM Manuals.
69.	OA Schedule 1, Section 3.3, specifically §3.3.1(d) (Spot Market Energy Charges)	785	2.0.0	500	"At that bus" language should be removed to avoid any confusion since spot market calculations are not location specific.	A Market Seller shall be paid for real-time sales of Spot Market Energy to the extent of its hourly net deliveries to the PJM Region of energy in excess of amounts scheduled in the Day-ahead Energy Market from the Market Seller's resources. For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the hourly amounts delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region. The total real-time generation revenues for each Market Seller shall be the sum of its payments determined by the product of (i) the hourly net amount of energy delivered to the PJM Region in excess of the amount scheduled to be delivered in that hour ~~at that bus~~ in the Day-ahead Energy Market from each of the Market Seller's resources, times (ii) the hourly Real-time System Energy Price. To the extent that the energy actually injected in any hour is less than the energy scheduled to be injected ~~at that bus~~ in the Day-ahead Energy Market, the Market Seller shall be debited for the difference at the Real-time System Energy Price at the time of the shortfall times the amount of the shortfall. The total generation revenue for each Market Seller shall be the sum, of the

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						revenues at Day-ahead System Energy Prices determined in accordance with the Day-ahead Energy Market as specified in Section 3.3.1(a) plus the revenues at Real-time System Energy Prices determined as specified herein, net of any debits specified herein for each Market Seller.
70.	OA Schedule 1, Section 5.1, specifically §5.1.1 (Transmission Congestion Charge Calculation - Calculation by Office of the Interconnection)	793	2.0.0	500	Section 9.3 does not exist in Schedule 1.	When the transmission system is operating under constrained conditions, or as necessary to provide third-party transmission provider losses ~~in accordance with Section 9.3~~, the Office of the Interconnection shall calculate Transmission Congestion Charges for each Network Service User, Market Participants in the PJM Interchange Energy Market, and each Transmission Customer.
71.	OA Schedule 1, Section 5.1, specifically §5.1.3(a) (Network Service User Calculation) (See also 5.4.3(a) below)	793 Continued	2.0.0	500	The terms "hourly congestion net bill" and "hourly losses net bill" are no longer used in any PJM FERC-accepted agreement or PJM Manual. This term was made obsolete when marginal losses was implemented but this section was not updated completely at that time. Therefore, the terms should be deleted to avoid potential confusion.	5.1.3 (a) Each Network Service User shall be charged for the increased cost of energy incurred by it during each constrained hour to deliver the output of its firm Generation Capacity Resources or other owned or contracted for resources, its firm bilateral purchases, and its non-firm bilateral purchases as to which it has elected to pay Transmission Congestion Charges. ~~The Transmission Congestion Charge for deliveries from each such source shall be the Network Service User's hourly congestion net bill.~~
72.	OA Schedule 1, Section §5.1.4 and 5.1.4A (Transmission Customer Calculation) (See also §5.4.4 and §5.4.4A below)	793 Continued	2.0.0	500	This revision is necessary to clarify that Network Imports and eSchedules Internal Bilateral Transactions are also charged Explicit Congestion and Explicit Losses. These changes should have been made when marginal losses were implemented but this section was not updated completely at that time. Additionally, the reference to "Real-time deviations from the Point-to-Point Transmission Service scheduled in the Day-ahead Energy Market shall be determined by the lesser of the real-time injection or withdrawal associated with such transmission service" may have been related to old losses paid-in-kind	**5.1.4 Transmission Customer Calculation.** Each Transmission Customer using Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), each Network Customer, and each Transmission Customer using Non-Firm Point-to-Point Transmission Service (as defined in the PJM Tariff) that has elected to pay Transmission Congestion Charges, shall be charged for the increased cost of energy during constrained hours for the delivery of energy using such ~~Point-to-Point~~ Transmission Service. Except as specified in this subsection, a Transmission Congestion Charge shall be assessed for transmission use scheduled in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region and the Day-ahead Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. Transmission Congestion Charges shall be assessed for real-time transmission use in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source Interface

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					language that PJM used to have in the OATT. For that reason, it should have been removed with the Marginal Losses implementation.	Pricing Point at the boundary of the PJM Region. A Transmission Customer shall be paid for Transmission Congestion Charges for real-time transmission use falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. ~~Real-time deviations from the Point-to-Point Transmission Service scheduled in the Day-ahead Energy Market shall be determined by the lesser of the real-time injection or withdrawal associated with such transmission service.~~ 5.1.4A Transaction Calculation. Each Market Participant entering into transactions in the PJM Interchange Energy Markets shall be charged for the increased cost of energy during constrained hours for the delivery of energy on the scheduled path. Except as specified in this subsection, a Transmission Congestion Charge shall be assessed for cleared MWh in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Congestion Price at the sink point and the Day-ahead Congestion Price at the source point. Transmission Congestion Charges shall be assessed for real-time cleared MWh in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Congestion Price at the sink point and the Real-time Congestion Price at the source point. Such Market Participant shall be paid for Transmission Congestion Charges for real-time cleared MWh falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Congestion Price at the sink point and the Real-time Congestion Price at the source point.
73.	OA Schedule 1, Section 5.1, specifically §5.1.7 (Total Transmission Congestion Charges)	793 Continued	2.0.0	500	The definition of Total Transmission Congestion Charges for allocation of credits should be clarified by way of a reference to the PJM Manuals since Manual 28, Section 7.4.2 is where the detail of all components of Total PJM Congestion Charges is specified.	The total Transmission Congestion Charges collected by PJMSettlement each hour will be the aggregate net amounts determined as specified in ~~this Schedule~~the PJM Manuals. PJMSettlement shall collect Transmission Congestion Charges for each hour the transmission system operates under constrained conditions.
74.	OA Schedule 1, Section 5.4, specifically §5.4.1 (Transmission Loss Charge Calculation -	796	3.0.0	500	Clarification for accuracy.	The Office of the Interconnection shall calculate Transmission Loss Charges for each Network Service User, Market Participant in the PJM Interchange Energy Market, and each Transmission Customer.

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	Calculation by Office of the Interconnection)					
75.	OA Schedule 1, Section 5.4, specifically §5.4.3(a) (Network Service User Calculation) (See also §5.1.3(a) above)	796 Continued	3.0.0	500	The terms "hourly congestion net bill" and "hourly losses net bill" are no longer used in any PJM FERC-accepted agreement or PJM Manual. This term was made obsolete when marginal losses was implemented but this section was not updated completely at that time. Therefore, the terms should be deleted to avoid potential confusion.	5.4.3(a) Each Network Service User shall be charged for the increased cost of transmission losses to deliver the output of its firm Capacity Resources or other owned or contracted for resources, its firm bilateral purchases, and its non-firm bilateral purchases. ~~The Transmission Loss Charge for deliveries from each such source shall be the Network Service User's hourly losses net bill.~~
76.	OA Schedule 1, Section 5.4, specifically §5.4.4 and 5.4.4A (Transmission Customer Calculation) (See also §5.1.4 and §5.1.4A above)	796 Continued	3.0.0	500	This revision is necessary to clarify that Network Imports and eSchedules Internal Bilateral Transactions are also charged Explicit Congestion and Explicit Losses. These changes should have been made when marginal losses were implemented but this section was not updated completely at that time. Additionally, the reference to "Real-time deviations from the Point-to-Point Transmission Service scheduled in the Day-ahead Energy Market shall be determined by the lesser of the real-time injection or withdrawal associated with such transmission service" may have been related to old losses paid-in-kind language that PJM used to have in the OATT. For that reason, it should have been removed with the Marginal Losses implementation.	**5.4.4 Transmission Customer Calculation.** Each Transmission Customer using Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), each Network Customer, and each Transmission Customer using Non-Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), shall be charged for the increased cost of transmission losses for the delivery of energy using ~~Point-to-Point~~such Transmission Service. Except as specified in this subsection, a Transmission Loss Charge shall be assessed for transmission use scheduled in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Loss Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region and the Day-ahead Loss Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. Transmission Loss Charges shall be assessed for real-time transmission use in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Loss Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Loss Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. A Transmission Customer shall be paid for Transmission Loss Charges for real-time transmission use falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Loss Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Loss Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region or the source Interface Pricing Point at the boundary of the PJM Region. ~~Real-time deviations from the Point-to-Point Transmission Service scheduled in the Day-ahead Energy Market shall be determined by the lesser of the real-time injection or withdrawal associated with such transmission service.~~

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						5.4.4A Transaction Calculation. Each Market Participant entering into transactions in the PJM Interchange Energy Market shall be charged for the increased cost of transmission losses on the scheduled path. Except as specified in this subsection, a Transmission Loss Charge shall be assessed for cleared MWh in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Loss Price at the sink point and the Day-ahead Loss Price at the source point. Transmission Loss Charges shall be assessed for real-time cleared MWh in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Loss Price at the sink point and the Real-time Loss Price at the source point. Such Market Participant shall be paid for Transmission Loss Charges for real-time cleared MWh falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Loss Price at the sink point and the Real-time Loss Price at the source point.
77.	OA Schedule 1, Section 6 (Must-Run" for Reliability Generation Introduction), specifically OA Schedule 1 - Section 6..1 (Introduction)	799	1.0.0	500	Deleting erroneous reference to Section 6.5, which should have been corrected in filing PJM submitted on June 16, 2008 in Docket Nos. EL08-34-001 and EL08-47-001.	~~Except as to the exempt generation resources identified in section 6.5 below, t~~The following procedures shall apply to any generation resource subject to the dispatch of the Office of the Interconnection that, as a result of transmission constraints, the Office of the Interconnection determines, in the exercise of Good Utility Practice, must be run in order to maintain the reliability of service in the PJM Region. The provisions of this Schedule shall otherwise apply to the scheduling, dispatch, operation and accounting treatment of such resources, to the extent not inconsistent with the provisions of this Section 6.
78.	OA, Schedule 6 specifically Schedule 6§1.5.6(g) (Development of the Recommended Regional Transmission Expansion Plan)	881	1.0.0	500	This proposed revision is related to the revision to OATT, Attachment DD, Section 15 (Coordination with Economic Planning Process) above regarding how costs for upgrades are allocated. To avoid potential conflicting language, PJM proposed to revise Section 15 of the OATT to cross reference Schedule 12 of the Tariff and Schedule 6 of the OA which specifies how upgrade costs are allocated. Additionally, Schedule 6, Section	(g) Based on the planning analysis and other input from participants, including any indications of a willingness to bear cost responsibility for an enhancement or expansion, the recommended plan shall, for any enhancement or expansion that is included in the plan, designate (1) the Market Participant(s) in one or more Zones, or any other party that has agreed to fully fund upgrades pursuant to this Agreement or the PJM Tariff, that will bear cost responsibility for such enhancement or expansion, as and to the extent provided by any provision of the PJM Tariff or this Agreement, (2) in the event and to the extent that no provision of the PJM Tariff or this Agreement assigns cost responsibility, the Market Participant(s) in one or more Zones from which the cost of such enhancement or expansion shall be recovered through charges established pursuant to Schedule 12 of the Tariff, and (3) in the event and to the extent that the Coordinated System Plan developed under the Joint Operating Agreement Between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C. assigns cost responsibility, the Market Participant(s) in one or more Zones from which the cost of such enhancement or expansion shall be recovered. Any designation under

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					1.5.6(g) prescribes generally the manner in which costs of RTEP enhancement or expansion shall be recovered through charges established pursuant to Schedule 12 of the Tariff. Therefore, for consistency PJM determined that it should move the discussion of how costs for transmission upgrades that are included in RTEP per OATT, Attachment DD, Section 15 from that section to Schedule 6 of the OA in which the cost allocation for other RTEP upgrades is generally discussed.	clause (2) of the preceding sentence (A) shall further be based on the Office of the Interconnection's assessment of the contributions to the need for, and benefits expected to be derived from, the pertinent enhancement or expansion by affected Market Participants and, (B)~~,~~ subject to FERC review and approval, shall be incorporated in any amendment to Schedule 12 of the PJM Tariff that establishes a Transmission Enhancement Charge Rate in connection with an economic expansion or enhancement developed under Sections 1.5.6(d) and 1.5.7 of this Schedule 6 ~~and~~, (C)~~,~~ the costs associated with expansions and enhancements required to ensure the simultaneous feasibility of stage 1A Auction Revenue Rights allocated pursuant to Section 7 of Schedule 1 of this Agreement shall (1) be allocated across transmission zones based on each zone's stage 1A eligible Auction Revenue Rights flow contribution to the total stage 1A eligible Auction Revenue Rights flow on the facility that limits stage 1A ARR feasibility and (2) within each transmission zone the Network Service Users and Transmission Customers that are eligible to receive stage 1A Auction Revenue Rights shall be the Responsible Customers under Section (b) of Schedule 12 of the PJM Tariff for all expansions and enhancements included in the Regional Transmission Expansion Plan to ensure the simultaneous feasibility of stage 1A Auction Revenue Rights, and (D) the costs associated with expansions and enhancements required to reduce to zero the Locational Price Adder for LDAs as described in Section 15 of Attachment DD of OATT shall (1) be allocated across transmission zones based on each zone's pro rata share of load in such LDA and (2) within each transmission zone, to all LSEs serving load in such LDA pro rata based on such load. Any designation under clause (3), above, (A) shall further be based on the Office of the Interconnection's assessment of the contributions to the need for, and benefits expected to be derived from, the pertinent enhancement or expansion by affected Market Participants, and (B), subject to FERC review and approval, shall be incorporated in an amendment to a Schedule of the PJM Tariff which establishes a charge in connection with the pertinent enhancement or expansion. Before designating fewer than all customers using Point-to-Point Transmission Service or Network Integration Transmission Service within a Zone as customers from which the costs of a particular enhancement or expansion may be recovered, Transmission Provider shall consult, in a manner and to the extent that it reasonably determines to be appropriate in each such instance, with affected state utility regulatory authorities and stakeholders. When the plan designates more than one responsible Market Participant, it shall also designate the proportional responsibility among them. Notwithstanding the foregoing, with respect to any facilities that the Regional Transmission Expansion Plan designates to be owned by an entity other than a Transmission Owner, the plan shall designate that entity as responsible for the costs of such facilities.
79.	OA, Schedule 8 (Delegation of PJM	896	1.0.0	500	The RAA Schedule 14 and the OA Schedule 8 present a list of	2. NEW PARTIES

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	Region Reliability Responsibilities), specifically OA Schedule 8, Section 2 (New Parties) (See also RAA, Schedule 14)				responsibilities that are delegated to PJM. The lists are identical except the RAA presents a requirement to establish standards and procedures for Demand Resources and the OA Schedule 8 does not. These inconsistencies need to be eliminated. PJM proposes to resolve inconsistencies between the two schedules.	With regard to the addition, withdrawal or removal of a party to the Reliability Assurance Agreement, the Office of the Interconnection shall: (a) Receive and evaluate the information submitted by entities that plan to serve loads within the PJM Region, including entities whose participation in the 895Agreement will expand the boundaries of the PJM Region. ~~s~~Such evaluation ~~to~~ shall be conducted in accordance with the requirements of the Reliability Assurance Agreement; and (b) Evaluate the effects of the withdrawal or removal of a party from the Reliability Assurance Agreement.
80.	OA, Schedule 8 (Delegation of PJM Region Reliability Responsibilities), specifically OA Schedule 8, Section 3 (Implementation of Reliability Assurance Agreement (See also RAA, Schedule 14)	897	1.0.0	500	The RAA Schedule 14 and the OA Schedule 8 present a list of responsibilities that are delegated to PJM. The lists are identical except the RAA presents a requirement to establish standards and procedures for Demand Resources and the OA Schedule 8 does not. These inconsistencies need to be eliminated. PJM proposes to resolve inconsistencies between the two schedules.	3. IMPLEMENTATION OF RELIABILITY ASSURANCE AGREEMENT With regard to the implementation of the provisions of the Reliability Assurance Agreement, the Office of the Interconnection shall: (a) Receive all required data and forecasts from the parties to the Reliability Assurance Agreement and other owners or providers of Capacity Resources; (b) Perform all calculations and analyses necessary to determine the Forecast Pool Requirement and the capacity obligations imposed under the Reliability Assurance Agreement, including periodic reviews of the capacity benefit margin for consistency with the Reliability Principles and Standards, as the foregoing terms are defined in the Reliability Assurance Agreement; (c) Monitor the compliance of each party to the Reliability Assurance Agreement with its obligations under the Reliability Assurance Agreement; (d) Keep cost records, and bill and collect any costs or charges due from the parties to the Reliability Assurance Agreement and distribute those charges in accordance with the terms of the Reliability Assurance Agreement; (e) Assist with the development of rules and procedures for determining and demonstrating the capability of Capacity Resources; (f) Establish the capability and deliverability of Generation Capacity Resources consistent with the requirements of the Reliability Assurance Agreement;

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						(g) Establish standards and procedures for Planned Demand Resources; (h) Collect and maintain generator availability data; (i~~h~~) Perform any other forecasts, studies or analyses required to administer the Reliability Assurance Agreement; (j~~i~~) Coordinate maintenance schedules for generation resources operated as part of the PJMRegion; (k~~j~~) Determine and declare that an Emergency exists or has ceased to exist in all or any part of the PJM Region or announce that an Emergency exists or ceases to exist in a Control Area interconnected with the PJM Region; (l~~k~~) Enter into agreements for (i) the transfer of energy in Emergencies in the PJM Region or in a Control Area interconnected with the PJM Region and (ii) mutual support in such Emergencies with other Control Areas interconnected with the PJM Region; and (m~~l~~) Coordinate the curtailment or shedding of load, or other measures appropriate to alleviate an Emergency, to preserve reliability in accordance with FERC, NERC or Applicable Regional Reliability Council principles, guidelines, standards and requirements and the PJM Manuals, and to ensure the operation of the PJM Region in accordance with Good Utility Practice.
PJM Reliability Assurance Agreement						
81.	RAA, Article I, Sections 1.31, 1.74 and 1.78 (Definitions)	206	6.0.0	500	The revisions to the definitions in Sections 1.3.1 and 1.78 are necessary because Single-Customer LSE will become an obsolete term when the provisions in Schedule 8.1 relating to Single-Customer LSEs are deleted from the RAA. The definition of Markets and Reliability Committee in Section 1.74 is duplicative of the same definition found in Section 1.46 of the RAA. Therefore, it	**1.31 FRR Service Area** FRR Service Area shall mean (a) the service territory of an IOU as recognized by state law, rule or order; (b) the service area of a Public Power Entity or Electric Cooperative as recognized by franchise or other state law, rule, or order; or (c) a separately identifiable geographic area that is: (i) bounded by wholesale metering, or similar appropriate multi-site aggregate metering, that is visible to, and regularly reported to, the Office of the Interconnection, or that is visible to, and regularly reported to an Electric Distributor and such Electric Distributor agrees to aggregate the load data from such meters for such FRR Service Area and regularly report such aggregated information, by FRR Service Area, to the Office of the Interconnection; and (ii) for which the FRR Entity has or assumes the obligation to provide capacity for all load (including load growth) within such area ~~excluding the load of Single-Customer LSEs that are FRR Entities~~. In the event that the service

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					should be deleted.	obligations of an Electric Cooperative or Public Power Entity are not defined by geographic boundaries but by physical connections to a defined set of customers, the FRR Service Area in such circumstances shall be defined as all customers physically connected to transmission or distribution facilities of such Electric Cooperative or Public Power Entity within an area bounded by appropriate wholesale aggregate metering as described above. 1.74 ~~Markets and Reliability Committee~~[Reserved for Future Use] ~~Markets and Reliability Committee shall mean the committee established pursuant to the Operating Agreement as a Standing Committee of the Members Committee.~~ 1.78 ~~Single-Customer LSE~~[Reserved for Future Use] ~~Single-Customer LSE shall mean a Party that (a) serves only retail customers that are Affiliates of such Party; (b) owns or controls generation facilities located at one or more of the retail customer location(s) that in the aggregate satisfy at least 50% of such Party's Unforced Capacity obligations; and (c) serves retail customers having (i) an Obligation Peak Load at all locations of no less than 100 MW, where such peak load of each such location is no less than 10 MW; or (ii) an Obligation Peak Load at each location served of no less than 25 MW.~~
82.	RAA, Article 2 (Purpose)	207	1.0.0	500	Revised reference to "existing Generation Capacity Resource" to the defined term "Existing Generation Capacity Resource."	This Agreement is intended to ensure that adequate Capacity Resources, including planned and Existing Generation Capacity Resources, planned and existing Demand Resources, Energy Efficiency Resources, and ILR will be planned and made available to provide reliable service to loads within the PJM Region, to assist other Parties during Emergencies and to coordinate planning of such resources consistent with the Reliability Principles and Standards. Further, it is the intention and objective of the Parties to implement this Agreement in a manner consistent with the development of a robust competitive marketplace. To accomplish these objectives, this Agreement is among all of the Load Serving Entities within the PJM Region. Unless this Agreement is terminated as provided in Section 3.3, every entity which is or will become a Load Serving Entity within the PJM Region is to become and remain a Party to this Agreement or to an agreement (such as a requirements supply agreement) with a Party pursuant to which that Party has agreed to act as the agent for the Load Serving Entity for purposes of satisfying the obligations under this Agreement related to the load within the PJM Region of that Load Serving Entity. Nothing herein is intended to abridge, alter or otherwise affect the emergency powers the Office of the Interconnection may exercise under the Operating Agreement and PJM Tariff.
83.	RAA, Article 5.2 (Breach by a Party)	215	1.0.0	500	Revisions are needed to ensure consistency with Section 15.1 of the Operating Agreement regarding	The provisions of Section 15.1 of the Operating Agreement shall apply to ~~If~~ a Party's (a) failures to pay any amount due under this Agreement ~~within 30 days after the~~ when due ~~date~~ or (b) ~~is in~~ breach of any material obligation under this Agreement~~, the Office of the Interconnection shall cause a notice of~~

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					breaches of agreements and the remedies available to PJM in cases of party breach or non-payment of amounts due.	~~such non-payment or breach to be sent to that Party~~. In addition to the remedies available to the Office of the Interconnection set forth in Section 15.1 of the Operating Agreement, ~~I~~if the Party fails~~,~~ ~~within 3 days of the receipt of such notice (except as otherwise described below),~~ to cure such non-payment or breach, ~~or if the breach cannot be cured within such time and if the Party does not diligently commence to cure the breach within such time and to diligently pursue such cure to completion,~~ the Office of the Interconnection and the remaining Parties may, without an election of remedies, exercise all remedies available at law or in equity or other appropriate proceedings. Such proceedings may include (ae) the commencement of a proceeding before the appropriate state regulatory commission(s) to request suspension or revocation of the breaching Party's license or authorization to serve retail load within the state(s) and/or (b~~d~~) bringing any civil action or actions or recovery of damages that may include, but not be limited to, all amounts due and unpaid by the breaching Party, and all costs and expenses reasonably incurred in the exercise of its remedies hereunder (including, but not limited to, reasonable attorneys' fees).
84.	RAA, Article 8 (Deficiency, Data Submission, and Emergency Charges), specifically RAA Article 8§1 (Nature of Charges)	226	1.0.0	500	Article 8, Section 8.1 should be revised to reflect that there are obligations in the RAA outside of Schedule 12 with which Members must comply.	Upon the advice and recommendations of the Members Committee, the PJM Board shall, subject to any Required Approvals, approve certain charges to be imposed on a Party for its failure to satisfy its obligations under this Agreement, as set forth in this Agreement~~Schedule 12~~.
85.	RAA, Article 8 (Deficiency, Data Submission, and Emergency Charges), specifically RAA Article 8§2 **(Determination of Charge Amounts.)**	227	1.0.0	500	Article 8, Section 8.2 should be revised to reflect that there are obligations in the RAA outside of Schedule 12 with which Members must comply.	No later than April 1 of each year, the Members Committee shall recommend to the PJM Board such charges to be applicable under this Agreement during the following Planning Period~~ and Schedule 12~~, which, upon approval by the PJM Board, shall be modified accordingly, subject to the receipt of all Required Approvals. The Markets and Reliability Committee may establish projected charges for estimating purposes only.
86.	RAA, Article 9 (Coordinated Planning and Operation), specifically RAA Article 9§1 (Overall Coordination)	230	1.0.0	500	Article 9, Section 9.1 should be updated to reflect the current environment since the implementation of RPM. Capacity Resource plans are no longer required nor do Members provide load forecasts to PJM.	Each Party shall cooperate with the other Parties in the coordinated planning and operation of their owned or contracted for Capacity Resources to obtain a degree of reliability consistent with the Reliability Principles and Standards. In furtherance of such cooperation each Party shall: (a) ~~coordinate its Capacity Resource plans with the other Parties to maintain reliable service to its own electric customers and those of the other Parties;~~

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						~~(b)~~ cooperate with the members and associate members of such Party's Applicable Regional Reliability Council to ensure the reliability of the region; (b~~e~~) make available its Capacity Resources to the other Parties through the Office of the Interconnection for coordinated operation and to supply the needs of the PJM Region for Operating Reserves; (c~~d~~) provide or arrange for Network Transmission Service or Firm Point-to-Point Transmission Service for service to the projected load of the Party and include all Capacity Resources as Network Resources designated pursuant to the PJM Tariff or Points of Receipt for Firm Point-to-Point Transmission Service; (d~~e~~) provide or arrange for sufficient reactive capability and voltage control facilities to meet Good Utility Practice and to be consistent with the Reliability Principles and Standards; (e~~f~~) implement emergency procedures and take such other coordination actions as may be necessary in accordance with the directions of the Office of the Interconnection in times of Emergencies; and (f~~g~~) maintain or arrange for Black Start Capability for a portion of its Capacity Resources at least equal to that established from time-to-time by the Office of the Interconnection.
87.	RAA, Article 9 (Coordinated Planning and Operation), specifically RAA Article 9§3 (Data Submission)	232	1.0.0	500	Article 9, Section 9.3 should be updated to reflect the current environment since the implementation of RPM. Capacity Resource plans are no longer required nor do Members provide load forecasts to PJM.	Each Party shall submit to the Office of the Interconnection the data and other information necessary for the performance of this Agreement as may be more fully described~~, including its plans for the addition, modification and removal of Capacity Resources, its load forecasts, and such other data set forth~~ in Schedule 11 hereof.
88.	RAA, Article 9 (Coordinated Planning and Operation), specifically RAA Article 9§4 (Charges	233	1.0.0	500	Article 9, Section 9.4 should be updated to reflect the current environment since the implementation of RPM. Capacity Resource plans are no longer required nor do Members provide load forecasts	(a) An emergency procedure charge, as set forth in Attachment DD to the PJM Tariff, shall be imposed on any Party that fails to comply with the directions of the Office of the Interconnection in times of Emergencies~~ pursuant to Section 9.1(f)~~

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	for Failures to Comply)				to PJM.	
89.	RAA, Schedule 7 (Plans to Meet Obligations)	279	1.0.0	500	LSEs submit their capacity data to PJM in eRPM prior to the commencement of a BRA. Capacity Resource plans are no longer submitted to PJM since the implementation of RPM. Therefore, the section needs to be revised to reflect the current market data submission process.	A. Each Party that elects to meet its estimated obligations for a Delivery Year by Self-Supply of Capacity Resources shall notify~~submit to~~ the Office of the Interconnection via the Internet site designated by the Office of the Interconnection ~~, no later than one month~~ prior to the start of the Base Residual Auction for such Delivery Year~~, its plans for such Capacity Resources, including (1) installation of Generation Capacity Resources (2) purchases, and (3) installation of Demand Resources, Energy Efficiency measures, or ILR~~. B. ~~The Capacity Resource plans of each Party shall indicate the nature and current status of each resource, including the status of a Planned Generation Capacity Resource or Planned Demand Resource, the potential for deactivation or retirement of a Generation Capacity Resource or Demand Resource, and the status of commitments for each sale or purchase of capacity included in its plans. The Office of the Interconnection will review the adequacy of the submittals hereunder both as to timing and content.~~ ~~C.~~ A Party that Self-Supplies Capacity Resources to satisfy its obligations for a Delivery Year must submit a Sell Offer as to such resource in the Base Residual Auction for such Delivery Year, in accordance with Attachment DD to the PJM Tariff. ~~D~~C. If, at any time after the close of the Third Incremental Auction for a Delivery Year, including at any time during such Delivery Year, a Capacity Resource that a Party has committed as a Self-Supplied Capacity Resource becomes physically incapable of delivering capacity or reducing load, the Party may submit a replacement Capacity Resource to the Office of the Interconnection. Such replacement Capacity Resource (1) may not be previously committed for such Delivery Year, (2) shall be capable of providing the same quantity of megawatts of capacity or load reduction as the originally committed Capacity Resource, and (3) shall meet the same locational requirements, if applicable, as the originally committed resource. In accordance with Attachment DD to the PJM Tariff, the Office of the Interconnection shall determine the acceptability of the replacement Capacity Resource.
90.	RAA, Schedule 8.1 (Fixed Resource Requirement Alternative) ,	283	2.0.0	500	The provisions related to Single-Customer LSEs should be deleted from Schedule 8.1, Section B because any party to the RAA that wanted to have	1. ~~Except as provided in subsection B.3 below, a~~A Party is eligible to select the FRR Alternative if it (a) is an IOU, Electric Cooperative, or Public Power Entity; and (b) demonstrates the capability to satisfy the Unforced Capacity obligation for all load in an FRR Service Area, including all expected load growth in such area, for the term of such Party's participation in the FRR Alternative.

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	specifically 8.1B (Eligibility)				such status, defined as "a Party that (a) serves only retail customers that are Affiliates of such Party; (b) owns or controls generation facilities located at one or more of the retail customer location(s) that in the aggregate satisfy at least 50% of such Party's Unforced Capacity obligations; and (c) serves retail customers having (i) an Obligation Peak Load at all locations of no less than 100 MW, where such peak load of each such location is no less than 10 MW; or (ii) an Obligation Peak Load at each location served of no less than 25 MW," had to have elected the FRR Alternative on or before April 1, 2008. No party has ever elected the Single-Customer LSE status to date and no party has the ability to elect that status after April 1, 2008. Therefore, the provisions relating to Single-Customer LSEs are obsolete and should be removed from the RAA.	2. A Party eligible under B.1 above may select the FRR Alternative only as to all of its load in the PJM Region; provided however, that a Party may select the FRR Alternative for only part of its load in the PJM Region if (a) the Party elects the FRR Alternative for all load (including all expected load growth) in one or more FRR Service Areas; (b) the Party complies with the rules and procedures of the Office of the Interconnection and all relevant Electric Distributors related to the metering and reporting of load data and settlement of accounts for separate FRR Service Areas; and (c) the Party separately allocates its Capacity Resources to and among FRR Service Areas in accordance with rules specified in the PJM Manuals. ~~3. Single-Customer LSEs as identified in accordance with subsection B.3.a below shall be eligible to elect the FRR Alternative upon the terms and conditions of this Schedule and the following additional terms and conditions. The aggregate Obligation Peak Load of all Single-Customer LSEs electing the FRR Alternative in the PJM Region shall not exceed 1000 MW.~~ ~~a) Single-Customer LSEs eligible for the FRR Alternative shall be limited to those that elected the FRR Alternative on or before April 1, 2008. The Office of the Interconnection, as necessary, shall establish and post in the PJM Manuals open-season procedures to apportion the maximum allowed service under the FRR Alternative among interested Single-Customer LSEs.~~ ~~b) The Single-Customer LSE must install and maintain wholesale metering at each location that is monitored by, and regularly reported to, the Office of the Interconnection.~~ ~~c) Each Single-Customer LSE warrants that (i) it has and shall maintain and enforce the contract right during the term of its election of the FRR Alternative to prohibit its retail customer(s) from terminating service from the Single-Customer LSE and obtaining such service from a different LSE; and (ii) it has and shall maintain for such term Financial Security or a Corporate Guaranty, both as defined in Attachment Q to the PJM Tariff, in an amount sufficient to cover any charge assessed under subsection B.3.c. A Single-Customer LSE will not violate its requirement under this subsection in the event that the retail customer terminates its service from the Single-Customer LSE and obtains service from an LSE that is an FRR Entity, provided that the Single-Customer LSE assigns Capacity Resources to the LSE providing such service in an amount equal to the Daily Unforced Capacity Obligation related to such retail customer.~~ ~~d) Each Single-Customer LSE shall obtain from its retail customer(s) and provide to the Office of the Interconnection and the entity designated under state law, order, or rule as such customer's default service provider or provider of last resort and the Electric Distributor a written statement agreeing that in the event such customer terminates its service from the Single-Customer LSE and obtains such service from a Party that is not an FRR Entity, then such customer's load shall be treated as ILR for the remaining duration of the period for which such Single-Customer LSE had elected the FRR Alternative, that for such purpose the Electric Distributor is authorized to obtain certification of such load as ILR, and that the customer agrees to provide the Electric Distributor with all information required for such certification. Nothing in this provision shall preclude such customer from using its~~

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						~~owned or controlled generation to facilitate the interruption of its load as ILR.~~ ~~e) A Single-Customer LSE shall be assessed an Unauthorized Load Transfer Charge in the event such LSE's retail customer terminates its service from such LSE and obtains service from a Party that has not elected the FRR Alternative, or in the event such load transfer occurs to a Party that has elected the FRR Alternative, but the Single-Customer LSE does not transfer sufficient Capacity Resources as required by subsection B.3.c. Such charge shall equal two times the Cost of New Entry times the Daily Unforced Capacity Obligation related to such customer for the remaining duration of the period for which such Single-Customer LSE elected the FRR Alternative.~~ ~~f) Each Single-Customer LSE shall provide to the Office of the Interconnection an FRR Capacity Plan in accordance with this schedule. Such FRR Capacity Plan, in addition to complying with all other applicable requirements of this Schedule, shall identify and commit for at least five delivery years Capacity Resources sufficient to satisfy such LSE's Daily Unforced Capacity Obligations hereunder consisting of generation assets or physical supply contracts that qualify as a 'forward contract' or a 'commodity contract' under the U.S. Bankruptcy Code. Each Single-Customer LSE warrants that all generation assets and forward supply contracts included in its FRR Capacity Plan shall be assigned to any successor-in-interest of its retail customer(s)'s assets and operations.~~
91.	RAA Schedule 8.1.E (Conditions on Purchases and Sales of Capacity Resources by FRR Entities)	286	2.0.0	500	Typo in Schedule 8.1, Section E.3 needs to be corrected.	3. An FRR Entity that designates Capacity Resources in its FRR Capacity Plan(s) for a Delivery Year based on the Threshold Quantity may not offer to sell such resources in any Reliability Pricing Model auction, ~~but,~~but may use such resources to meet any increased capacity obligation resulting from unanticipated growth of the loads in its FRR Capacity Plan(s), or may sell such resources to serve loads located outside the PJM Region, or to another FRR Entity, subject to subsection E.1 above.
92.	RAA, Schedule 8.1G (Capacity Resource Performance)	288	3.0.0	500	Corrected reference in Schedule 8.1, Section G to change "RPM auction" to the defined term "RPM Auction."	Any Capacity Resource committed by an FRR Entity in an FRR Capacity Plan for a Delivery Year shall be subject during such Delivery Year to the charges set forth in sections 7, 9, 10, 11, and 13 of Attachment DD to the PJM Tariff; provided, however, the Daily Deficiency Rate under sections 7, 9, and 13 thereof shall be 1.20 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions), and the charge rates under section 10 thereof, shall be the Capacity Resource Clearing Price resulting from the RPM Auctions for the Delivery Year for the LDA encompassing the Zone of the

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						FRR Entity, weight-averaged as described above. An FRR Entity shall have the same opportunities to cure deficiencies and avoid or reduce associated charges during the Delivery Year that a Market Seller has under Sections 7, 9, and 10 of Attachment DD to the PJM Tariff. An FRR Entity may cure deficiencies and avoid or reduce associated charges prior to the Delivery Year by procuring replacement Unforced Capacity outside of any RPM ~~a~~Auction and committing such capacity in its FRR Capacity Plan.
93.	RAA, Schedule 10.1 (Locational Deliverability Areas and Requirements)	295	4.0.0	500	Schedule 10.1 should be amended to support integration activities/ expansion initiatives create new LDAs. This language allows for a zone that will be located in the PJM footprint in the future as the result of an integration into the RTO to be modeled as an LDA in an RPM auction in which the new zone is included even though the zone is not yet specifically listed as an LDA.	The capacity obligations imposed under this Agreement recognize the locational value of Capacity Resources. To ensure that such locational value is properly recognized and quantified, the Office of the Interconnection shall follow the procedures in this Schedule. A. ~~Following the Transition Period, as such term is defined in Attachment DD to the Tariff, t~~The Locational Deliverability Areas for the purposes of determining locational capacity obligations hereunder, but not necessarily for the purposes of the Regional Transmission Expansion Planning Protocol, shall consist of the following Zones (as defined in Schedule 15), combinations of such Zones, and portions of such Zones: . . . • PSEG northern region (north of Linden substation); and • DPL southern region (south of Chesapeake and Delaware Canal The Locational Deliverability Areas for the purposes of determining locational capacity obligations hereunder, but not necessarily for the purposes of the Regional Transmission Expansion Planning Protocol, shall also include any new Zones expected to be integrated into PJM prior to the commencement of the Base Residual Auction for the Delivery Year for which the locational capacity obligation is being determined.
94.	RAA, Schedule 11 (Data Submittals)	293	1.0.0	500	Revisions needed to accurately reflect the current market environment. LSEs no longer provide their load forecasts to PJM. Capacity Resource plans are no longer required to be submitted to PJM.	To perform the studies required to determine the Forecast Pool Requirement and Daily Unforced Capacity Obligations under this Agreement and to determine compliance with the obligations imposed by this Agreement, each Party and other owner of a Capacity Resource shall submit data to the Office of the Interconnection in conformance with the following minimum requirements: 1. All data submitted shall satisfy the requirements, as they may change from time to time, of any procedures adopted by the Members Committee. 2. Data shall be submitted in an electronic format, or as otherwise specified by the Markets and Reliability Committee and approved by the PJM Board.

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						3. Actual outage data for each month for Generator Forced Outages, Generator Maintenance Outages and Generator Planned Outages shall be submitted so that it is received by such date specified in the PJM Manuals. 4. On or before the date specified in the PJM Manuals, planned and maintenance outage data for all Generation Resources ~~and load forecasts (including seasonal and average weekly peaks)~~ shall be submitted. ~~5. On or before the date specified in the PJM Manuals, adjustments to forecasts shall be submitted.~~ ~~6. On or before the date or schedule for updates specified in the PJM Manuals, revisions to capacity and load forecasts (including the plans for satisfying the Daily Unforced Capacity Obligation of the Party) shall be submitted.~~ ~~7. Capacity plans or revisions to previously submitted capacity plans, required under Schedule 6.~~ ~~8. As desired by a Party, revisions to monthly peak load forecasts may be submitted.~~ The Parties acknowledge that additional information required to determine the Forecast Pool Requirement is to be obtained by the Office of the Interconnection from Electric Distributors in accordance with the provisions of the Operating Agreement.
95.	RAA, Schedule 13 (Emergency Procedure Charges)	296	1.0.0	500	Revision is needed because the current language is inconsistent with OATT, Att. DD, Section 13.1 which says "evaluated as recommended by the MRC and directed by the PJM Board."	Following an Emergency, the compliance of each Party with the instructions of the Office of the Interconnection shall be evaluated as ~~directed~~recommended by the Markets and Reliability Committee and directed by the PJM Board. If, based on such evaluation, it is determined that a Party refused to comply with, or otherwise failed to employ its best efforts to comply with, the instructions of the Office of the Interconnection to implement PJM emergency procedures, that Party shall pay an emergency procedure charge, as set forth in Attachment DD to the PJM Tariff. The revenue associated with Emergency Procedure Charges shall be allocated in accordance with Attachment DD to the PJM Tariff.
96.	RAA, Schedule 14 (Delegation to the Office of the Interconnection – of responsibilities under	297	1.0.0	500	The RAA Schedule 14 and the OA Schedule 8 present a list of responsibilities that are delegated to PJM. The lists are identical except the RAA presents a requirement to establish	The following responsibilities shall be delegated by the Parties to the Office of the Interconnection: 1. New Parties. With regard to the addition, withdrawal or removal of a Party the Office of the Interconnection shall: (a) Receive and evaluate the information submitted by entities that plan to serve loads within the PJM Region, including entities whose participation

No.	PJM Section Title	Record ID	Version	Priority Code	Reason for Proposed Revision	Proposed Revision
	RAA) (See also OA, Schedule 8)				standards and procedures for Demand Resources and the OA Schedule 8 does not. These inconsistencies need to be eliminated. PJM proposes to resolve inconsistencies between the two schedules.	in the Agreement will expand the boundaries of the PJM Region. Such evaluation shall be conducted in accordance with the requirements of the Agreement. (b) Evaluate the effects of the withdrawal or removal of a Party from this Agreement. 2. Implementation of Reliability Assurance Agreement. With regard to the implementation of the provisions of this Agreement the Office of the Interconnection shall: (a) Receive all required data and forecasts from the Parties and other owners or providers of Capacity Resources; (b) Perform all calculations and analyses necessary to determine the Forecast Pool Requirement and the capacity obligations imposed under the Reliability Assurance Agreement, including periodic reviews of the capacity benefit margin for consistency with the Reliability Principles and Standards; (c) Monitor the compliance of each Party with its obligations under the Agreement; (d) Keep cost records, and bill and collect any costs or charges due from the Parties and distribute those charges in accordance with the terms of the Agreement; (e) Assist with the development of rules and procedures for determining and demonstrating the capability of Capacity Resources; (f) Establish the capability and deliverability of Generation Capacity Resources consistent with the requirements of the Reliability Assurance Agreement; (g) Establish standards and procedures for Planned Demand Resources; (h) Collect and maintain generator availability data; (i) Perform any other forecasts, studies or analyses required to administer the Agreement; (j) Coordinate maintenance schedules for generation resources operated as part of the PJM Region; (k) Determine and declare that an Emergency exists or has ceased to exist in all or any part of the PJM Region or announce that an Emergency exists or ceases to exist in a Control Area interconnected with the PJM Region; (l) Enter into agreements for (i) the transfer of energy in Emergencies in the PJM Region or in a Control Area interconnected with the PJM Region and

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						(ii) mutual support in such Emergencies with other Control Areas interconnected with the PJM Region; and (m) Coordinate the curtailment or shedding of load, or other measures appropriate to alleviate an Emergency, to preserve reliability in accordance with FERC, NERC or Applicable Regional Reliability Council principles, guidelines, standards, ~~and~~ requirements and the PJM Manuals, and to ensure the operation of the PJM Region in accordance with Good Utility Practice.

Attachment B

(Marked Sections / Redline Format)

PJM Open Access Transmission Tariff
(Marked Sections / Redline Format)

110.1 Application

The Generation Interconnection Customer desiring the interconnection of a new Generation Capacity Resource of 20 MW or less or the increase in capacity, by 20 MW or less, of an ~~existing~~ Existing Generation Capacity Resource, must submit a completed Attachment N – Form of Generation Interconnection Feasibility Study Agreement. Attachment N of the PJM Tariff may be found on the PJM web site at and must be submitted to Transmission Provider.

All requirements related to the submission, for a larger resource, of an Attachment N application must be satisfied for a capacity addition of 20 MW or less, including (i) an initial deposit in the amount of $100 for each MW requested if the Generation Interconnection Request is received within the first calendar month of the current New Services Queue; an initial deposit in the amount of $150 for each MW requested if the Generation Interconnection Request is received within the second calendar month of the current New Services Queue; or an initial deposit in the amount of $200 for each MW requested, if the Generation Interconnection Request is received within the third calendar month of the current New Services Queue; and (ii) a base non-refundable deposit in the amount of $1,000, if the Generation Interconnection Request is received within the first calendar month of the current New Services Queue; a base non-refundable deposit in the amount of $2,000 if the Generation Interconnection Request is received within the second calendar month of the current New Services Queue; or a base non-refundable deposit of $3,000, if the Generation Interconnection Request is received within the third calendar month of the current New Services Queue.

The base and initial per MW deposit received will be credited toward the Generation Interconnection Customer's cost responsibility for the Generation Interconnection Feasibility Study. Upon completion of the Feasibility Study, the Transmission Provider will return any unused refundable deposit monies to Interconnection Customer. Any remaining non-refundable deposit monies will be credited toward the Interconnection Customer's cost responsibility for any other studies conducted for that Interconnection Request under Part VI of the Tariff, which will be applied prior to the deposit monies collected for that other study. If any non-refundable deposit monies remain after all studies are complete, such monies will be returned to a Generation Interconnection Customer upon Initial Operation, or to a Transmission Interconnection Customer upon energization of completed facilities as provided in Attachment GG, Appendix III, Section 20 of the Tariff. The Generation Interconnection Customer is responsible for all actual costs associated with the processing of the request and the performance of the Feasibility Study related to the request and will be billed for such costs following the completion of the Feasibility Study.

Documentation of site control must be submitted, for small resource additions, with the completed Attachment N. Site control may be demonstrated through an exclusive option to purchase the property on which the generation project is to be developed, a property deed, or a range of tax or corporate documents that identify property ownership. Site control must either be in the name of the party submitting the generation interconnection request or documentation must be provided establishing the business relationship between the project developer and the party having site control.

All information required in the completed Attachment N related to the generating project site, Point of Interconnection, and generating unit size and configuration must be provided.
Once it has been established that the requirements related to the submission of the Attachment N application have been met, the Generation Interconnection Request will be entered into the then current New Services Queue for analysis. The generation addition project will be identified in the New Services Queue on the PJM web site by the size of the capacity addition and by its proposed Point of Interconnection on the PJM system.

110.5 Interconnection Service Agreement

As with larger generation projects, an Interconnection Service Agreement must be executed and filed with the FERC. The Interconnection Service Agreement identifies the obligations, on the part of the Interconnection Customer, to pay for transmission facilities required to facilitate the interconnection and the Capacity Interconnection Rights which are awarded to the *Generation* Capacity Resource.

In general, the execution of an Interconnection Service Agreement is no different for capacity additions of 20 MW or less than for larger *Generation* Capacity Resources. However, in instances where an increase of 20 MW or less to an ~~existing~~ Existing *Generation* Capacity Resource can be put in service immediately, a modified Interconnection Service Agreement may be executed. If such an increase is expedited through the System Impact Study phase, ahead of larger projects already in the New Services Queue, an Interconnection Service Agreement will be executed granting interim Capacity Interconnection Rights. These interim rights will allow the capacity increase to be implemented and the resource to participate in the capacity market until studies have been completed for earlier queued resources and all related obligations have been defined. At such time, the interim rights awarded the smaller capacity addition will become dependent on the construction of any required transmission facilities and the satisfaction of any financial obligations for those facilities. If, once those obligations are defined, the smaller capacity addition desires to retain the interim Capacity Interconnection Rights; a new Interconnection Service Agreement will be executed.

If a new Generation Capacity Resource of 20 MW or less can be quickly connected to the system, interim Capacity Interconnection Rights can be awarded, as above, through the execution of a modified Interconnection Service Agreement.

SCHEDULE 2
Reactive Supply and Voltage Control from Generation or Other Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided directly by the Transmission Provider. The Transmission Customer must purchase this service from the Transmission Provider.

In addition to the charges and payments set forth in this Schedule 2, Market Sellers providing reactive services at the direction of the Office of the Interconnection shall be credited for such services, and Market Participants shall be charged for such services, as set forth in section 3.2.3B of the Appendix to Attachment K.

The Transmission Provider shall administer the purchases and sales of Reactive Supply. PJMSettlement shall be the Counterparty to (a) the purchases of Reactive Supply from owners of Generation or Other Sources and Market Sellers and (b) the sales of Reactive Supply to Transmission Customers and Market Participants.

Charges

Purchasers of Reactive Supply and Voltage Control from Generation or Other Sources Service shall be charged for such service in accordance with the following formulae.

Monthly Charge for a purchaser receiving Network Integration Transmission Service or Point-to-Point Transmission Service to serve Non-Zone Load = Allocation Factor * Total Generation or other source Owner Monthly Revenue Requirement

Monthly Charge for a purchaser receiving Network Integration Transmission Service or Point-to-Point Transmission Service to serve Zone Load = Allocation Factor * Zonal Generation or other source Owner Monthly Revenue Requirement * Adjustment Factor

Where:

Purchaser serving Non-Zone Load is a Network Customer serving Non-Zone Network Load or serving Network Load in a zone with no revenue requirement

for Reactive Supply and Voltage Control from Generation or Other Sources Service, or a Transmission Customer where the Point of Delivery is at the boundary of the PJM Region.

Zonal Generation or other source Owner Monthly Revenue Requirement is the sum of the monthly revenue requirements for each generator or other source located in a Zone, as such revenue requirements have been accepted or approved, upon application, by the Commission.

Total Generation or other source Owner Monthly Revenue Requirement is the sum of the Zonal Generation or other source Owner Monthly Revenue Requirements for all Zones in the PJM Region.

Allocation Factor is the monthly transmission use of each Network Customer or Transmission Customer per Zone or Non-Zone, as applicable, on a megawatt basis divided by the total transmission use in the Zone or in the PJM Region, as applicable, on a megawatt basis.

For Network Customers, monthly transmission use on a megawatt basis is the sum of a Network Customer's daily values of DCPZ or DCPNZ (as those terms are defined in Section 34.1) as applicable, for all days of the month.

For Transmission Customers, monthly transmission use on a megawatt basis is the sum of the Transmission Customer's hourly amounts of Reserved Capacity –for each day of~~in~~ the month (not curtailed by PJM) divided by the number of hours in the day~~24~~.

Adjustment Factor is determined as the sum of the total monthly transmission use in the PJM Region, exclusive of such use by Transmission Customers serving Non-Zone Load, divided by the total monthly transmission use in the PJM Region on a megawatt basis.

In the event that a single customer is serving load in more than one Zone, or serving Non-Zone Load as well as load in one or more Zones, or is both a Network Customer and a Transmission Customer, the Monthly Charge for such a customer shall be the sum of the Monthly Charges determined by applying the appropriate formulae set forth in this Schedule 2 for each category of service.

Payment to Generation or Other Source Owners

Each month, the Transmission Provider shall pay each Generation or other source Owner an amount equal to the Generation or other source Owner's monthly revenue requirement as accepted or approved by the Commission. In the event a Generation or other source Owner sells a Generation Capacity Resource(s) which is included in its current effective monthly revenue requirement accepted or approved by the Commission, payments in that Generation or other

source Owner's Zone may be allocated as agreed to by the owners of Generation Capacity Resources in that Zone. Such Generation or other source Owners shall inform Transmission Provider of any such agreement. In the absence of agreement among such Generation or other source Owners, the Commission, upon application, shall establish the allocation. Generation Owners shall not be eligible for payment, pursuant to this Schedule 2, of monthly revenue requirement associated with those portions of generating units designated as Behind The Meter Generation. The Transmission Provider shall post on its website a list for each Zone of the annual revenue requirements for each Generation Owner receiving payment within such Zone and specify the total annual revenue requirement for all of the Transmission provider.

SCHEDULE 3
Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources ~~(generation and interchange)~~ with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line resources ~~generation~~ whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The amount of and charges for Regulation and Frequency Response Service are set forth below. The Transmission Provider shall administer the purchases of Regulation Service in the PJM Interchange Energy Market. PJMSettlement shall be the Counterparty to the purchases by customers of Regulation Service in the PJM Interchange Energy Market; provided however, that PJMSettlement shall not be the contracting party to bilateral transactions between market participants or with respect to a self-schedule or self-supply of ~~generation~~ resources by a customer to satisfy its Regulation obligation.

For ~~r~~Regulation not satisfied by individual Transmission Owners on behalf of their Native Load Customers, Network Customers or other Transmission Customers serving load in the PJM Region, the Transmission Provider will order the lowest cost alternative for ~~r~~Regulation in service as needed to meet the ~~r~~Regulation requirements of each Regulation Zone (as may be set forth in the PJM Manuals~~),~~ and as specified below:

a. Regulation shall be supplied to meet the Regulation objective of a Regulation Zone from ~~generators~~resources located within the metered electrical boundaries of such Regulation Zone. Resources~~Generators~~ offering ~~r~~Regulation shall comply with applicable standards and requirements for ~~r~~Regulation capability and dispatch specified in the procedures of the Office of the Interconnection.

b. The Office of the Interconnection shall obtain and maintain an amount of ~~r~~Regulation for each Regulation Zone equal to the Regulation objective for such Regulation Zone, as specified in its procedures.

c. The ~~r~~Regulation range of a resource~~unit~~ shall be at least twice the amount of ~~r~~Regulation assigned.

d. A resource~~unit~~ capable of automatic energy dispatch that is also providing ~~r~~Regulation shall have its energy dispatch range reduced from the ~~r~~Regulation range by twice the amount of the ~~r~~Regulation provided. The amount of ~~r~~Regulation provided by a resource~~unit~~ shall serve to redefine the normal minimum generation and normal maximum generation energy limits of that

unit, in that the amount of ~~r~~Regulation shall be added to the unit's normal minimum generation energy limit, and subtracted from its normal maximum generation energy limit.

e. Qualified ~~r~~Regulation must satisfy the verification tests described in the procedures of the Office of the Interconnection.

f. A Transmission Owner, Network Customer or other Transmission Customer may satisfy its ~~r~~Regulation obligation from its own resources capable of performing ~~r~~Regulation service, by contractual arrangements with others able to provide ~~r~~Regulation service on a comparable basis, or by purchases from~~, as applicable,~~ the PJM ~~r~~Regulation market. ~~in the MAAC Control Zone, the regulation market in the VACAR Control Zone or the regulation market in the PJM West Region.~~

g. The Office of the Interconnection shall obtain ~~r~~Regulation service from the least-cost alternatives available from either pool-scheduled or self-scheduled resources as needed to meet Regulation~~Control~~ Zone requirements not otherwise satisfied by a Transmission Owner, Network Customer or other Transmission Customer, in accordance with Section 1.11.4(b) of Attachment K-Appendix.

h. The Office of the Interconnection shall dispatch resources for ~~r~~Regulation by sending ~~r~~Regulation signals and instructions to resources from which ~~r~~Regulation service has been offered, in accordance with the procedures of the Office of the Interconnection. Those resources shall comply with ~~r~~Regulation dispatch signals and instructions transmitted by the Office of the Interconnection and, in the event of conflict, ~~r~~Regulation dispatch signals and instructions shall take precedence over energy dispatch signals and instructions. Those providing ~~r~~Regulation shall exert all reasonable efforts to operate, or ensure the operation of, their resources supplying load in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

i. Each Transmission Owner (on behalf of its Native Load Customers), Network Customer or other Transmission Customer serving load within a ~~Control~~Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such ~~Control~~Regulation Zone for such hour, based on the entity's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such ~~Control~~Regulation Zone for such hour.

j. An entity supplying ~~r~~Regulation at the direction of the Office of the Interconnection in excess of its hourly ~~r~~Regulation obligation shall be credited for each increment of such ~~r~~Regulation at the price specified in Sections 3.2.2 and 3.3.2 of Attachment K-Appendix. A Transmission Owner, Network Customer or other Transmission Customer that does not meet its hourly ~~r~~Regulation obligation shall be charged for ~~r~~Regulation dispatched by the Office of the Interconnection to meet such obligation at the price specified in Sections 3.2.2 and 3.3.2 of Attachment K-Appendix.

SCHEDULE 6A
Black Start Service

References to section numbers in this Schedule 6A refer to sections of this Schedule 6A, unless otherwise specified.

To ensure the reliable restoration following a shut down of the PJM transmission system, Black Start Service is necessary to facilitate the goal of complete system restoration. Black Start Service enables Transmission Provider and Transmission Owners to designate specific generators called Black Start Units whose location and capabilities are required to re-energize the transmission system following a system-wide blackout. The Transmission Provider shall administer the provision of Black Start Service. PJMSettlement shall be the Counterparty to the purchases and sales of Black Start Service.

TRANSMISSION CUSTOMERS

1. All Transmission Customers and Network Customers must obtain Black Start Service through the Transmission Provider, with PJMSettlement as the Counterparty, pursuant to this Schedule 6A.

PROVISION OF BLACK START SERVICE

2. A Black Start Unit is a generating unit that has equipment enabling it to start without an outside electrical supply or a generating unit with a high operating factor (subject to Transmission Provider concurrence) with the demonstrated ability to automatically remain operating, at reduced levels, when disconnected from the grid. A Black Start Unit shall be considered capable of providing Black Start Service only when it meets the criteria set forth in the PJM manuals. For the purposes of this Schedule 6A, the expected life of the Black Start Unit shall take into consideration expectations regarding both the enabling equipment and the generation unit itself.

3. A Black Start Plant is a generating plant that includes one or more Black Start Units. A generating plant with Black Start Units electrically separated at different voltage levels will be considered multiple Black Start Plants.

4. The Transmission Provider, in conjunction with the Transmission Owners, are responsible for developing a coordinated and efficient system restoration plan that identifies all of the locations where Black Start Units are needed. The PJM Manuals shall set forth the criteria and process for selecting or identifying the Black Start Units necessary to commit to providing Black Start Service at the identified locations.. No more than three Black Start Units at a Black Start Plant will be eligible for compensation under this Schedule 6A, unless specifically approved by the Transmission Provider as an exception. No Black Start Unit shall be eligible to recover the costs of providing Black Start Service in the PJM Region unless it agrees to provide such service for a term of commitment established under section 5 or 6 below.

5. Owners of Black Start Units selected to provide Black Start Service in accordance with section 4 and electing to forego any recovery of new or additional Black Start Capital Costs shall

commit to provide Black Start Service from such Black Start Units for an initial term of no less than two years and authorize the Transmission Provider to resell Black Start Service from its Black Start Units. The term commitment shall continue to extend until the Black Start Unit owner, or the Transmission Owner, with the consent of the Transmission Provider, or the Transmission Provider, with the consent of the Transmission Owner, provides written, one-year advance notice of its intention to terminate the commitment.

6. Owners of Black Start Units selected to provide Black Start Service in accordance with section 4 and electing to recover new or additional Black Start Capital Costs shall commit to provide Black Start Service from such Black Start Units for a term based upon *the age of* the Black Start Unit *or the longest expected life of the Incremental Black Start Capital Cost*, as set forth in the *applicable* CRF Tables in Paragraph 18. *For those Black Start Units that elect to recover new or additional Black Start Capital Costs in addition to a prior, FERC-approved cost recovery rate, the applicable commitment period shall be the longer of the FERC-approved recovery period or the applicable term of commitment as set forth in the CRF Tables in Paragraph 18.* Either the Transmission Provider, with the consent of the Transmission Owner, or the Transmission Owner, with the consent of the Transmission Provider, may terminate the commitment with one year advance notice of its intention to the Black Start Unit owner, but the Transmission Owner shall reimburse the Black Start Unit owner for any amount of unrecovered Fixed Black Start Service Costs over a period not to exceed five years. A Black Start Unit owner may terminate the provision of Black Start Service with one year advance notice (or its commitment period may be involuntarily terminated pursuant to the section 15 below). Such Black Start Unit shall forego any otherwise existing entitlement to future revenues collected pursuant to this Schedule 6A and fully refund any amount of the Black Start Capital Costs recovered under a FERC-approved rate (recovered on an accelerated basis pursuant to the provisions of section 17(i)) in excess of the amount that would have been recovered pursuant to section 18 during the same period. At the conclusion of the term of commitment established under this section 6, a Black Start Unit shall commence a new term of commitment under either section 5 or 6, as applicable.

6A. In the event that a Black Start Unit fails to fulfill its commitment established under section 5 to provide Black Start Service, receipt of any Black Start Service revenues associated with the non-performing Black Start Unit shall cease and, for the period of the unit's non-performance, the Black Start Unit owner shall forfeit the Black Start Service revenues associated with the non-performing Black Start Unit that it received or would have received had the Black Start Unit performed, not to exceed revenues for a maximum of one year.

In the event that a Black Start Unit fails to fulfill its commitment established under section 6 above, such unit shall forego any otherwise existing entitlement to future revenues collected pursuant to this Schedule 6A and fully refund any amount of the Black Start Capital Costs recovered under a FERC-approved rate (recovered on an accelerated basis pursuant to the provisions of section 17(i)) in excess of the amount that would have been recovered pursuant to section 18 during the same period, but such unit remains eligible to establish a new commitment under section 5 or 6.

Performance Standards and Outage Restrictions

7. Black Start Units must have the capabilities listed below. These capabilities must be demonstrated in accordance with the criteria set forth in the PJM manuals and will remain in effect for the duration of the commitment to provide Black Start Service.

a. A Black Start Unit must be able to close its output circuit breaker to a dead (de-energized) bus within 90 minutes of a request from the Transmission Owner or the Transmission Provider.

b. A Black Start Unit must be capable of maintaining frequency and voltage under varying load.

c. A Black Start Unit must be able to maintain rated output for a period of time identified by each Transmission Owner's system restoration requirements, in conjunction with the Transmission Provider.

8. Each owner of Black Start Units or Black Start Plants must maintain procedures for the start-up of the Black Start Units.

9. If a Black Start Unit is a generating unit with a high operating factor (subject to Transmission Provider concurrence) with the ability to automatically remain operating at reduced levels when disconnected from the grid, this ability must be demonstrated in accordance with the criteria set forth in the PJM manuals.

10. No more than one Black Start Unit at a Black Start Plant may be subject to planned maintenance at any one time. This restriction excludes outages on common plant equipment that may make all units unavailable. A Black Start Unit not currently designated as critical and on the same voltage level may be substituted for a Black Start Unit that is subject to a planned outage to permit a concurrent planned outage of another critical Black Start Unit at the Black Start Plant to begin. The Black Start Unit used as a substitute must have had a valid annual test within the previous 12 months.

11. Concurrent planned outages at multiple Black Start Plants within a zone may be restricted based on Transmission Owner requirements for Black Start Service availability. Such restrictions must be predefined and approved by Transmission Provider in accordance with the PJM manuals.

Testing

12. To verify that they can be started and operated without being connected to the Transmission System, Black Start Units designated as critical shall be tested annually in accordance with the PJM manuals. The Black Start Unit owner shall determine the time of the annual test.

13. Compensation for energy output delivered to the Transmission System during the annual test shall be provided for the Black Start Unit's minimum run time at the higher of the unit's

cost-capped offer or real-time Locational Marginal Price plus start-up and no-load costs for up to two start attempts, if necessary. For Black Start Units that are generating units with a high operating factor (subject to Transmission Provider's concurrence) with the ability to automatically remain operating at reduced levels when disconnected from the grid, an opportunity cost will be provided to compensate the unit for lost revenues during testing.

14. To receive Black Start Service revenues, a Black Start Unit must have a successful annual test on record with the Transmission Provider within the preceding 13 months.

15. If a Black Start Unit fails the annual test, the unit may be re-tested within a ten-day period without financial penalty. If the Black Start Unit does not successfully re-test within that ten-day period, monthly Black Start Service revenues will be forfeited by that unit from the time of the first unsuccessful test until such time as the unit passes an annual test. If the Black Start Unit owner determines not to make the necessary repairs to enable the Black Start Unit to pass the annual test, the Black Start Unit owner will have failed to fulfill its commitment pursuant to section 5 or section 6, whichever is applicable, of this Schedule 6A and will be subject to the additional forfeiture of revenues set forth in section 6A.

Revenue Requirements

16. The annual Black Start Service revenue requirement shall be the sum of the annual Black Start Service revenue requirements for each generator that is designated as providing Black Start Service and has provided the Transmission Provider with a calculation of its annual Black Start Service revenue requirements. A separate line item shall appear on the participants' Transmission Provider bill for Black Start Service charges and credits.

17. Black Start Service revenue requirements for each Black Start Unit shall be based, at the election of the owner, on either (i) a FERC-approved rate for the recovery of the cost of providing such service for the entire duration of the commitment term set forth in either section 5 or 6, as applicable, or (ii) the formula *rates* set forth in section 18 of this Schedule 6A for the commitment term set forth in *Paragraph* 5 or 6 as applicable. Each generator's Black Start Service revenue requirements shall be an annual calculation. Requests for changes to the Black Start Service revenue requirements must be submitted to the Market Monitoring Unit for review and analysis, with supporting data and documentation, pursuant to section III of Attachment M – Appendix and the PJM Manuals. The Market Monitoring Unit and the generator owner shall attempt to come to agreement on the level of each component included in the Black Start Service revenue requirements. The Black Start Service generator owner may submit Black Start Service revenue requirements that it chooses, provided that (i) it has participated in good faith with the process described in this section and in section III of Attachment M - Appendix, (ii) the Black Start Service revenue requirements are no higher than the level defined in any agreement reached by the Black Start Service generator owner and the Market Monitoring Unit that resulted from the foregoing process, and (iii) the Black Start Service revenue requirements are accepted by the Office of the Interconnection subject to the criteria set forth in the Tariff.

In the event that the Black Start Service generator owner and Market Monitoring Unit cannot agree on the level of each component included in the calculation of the Black Start Service

revenue requirements, and the Black Start Service generator owner submits its own values to the Office of the Interconnection that are inconsistent with the Market Monitoring Unit's determination, the Office of the Interconnection shall determine whether to accept such values subject to the requirements of the Tariff and the PJM Manuals. If the Office of the Interconnection does not accept the values submitted by the Black Start Service generator owner in such case, the Black Start Service generator owner may file its proposed values with the Commission for approval. Pursuant to section III of Attachment M - Appendix, if the Office of the Interconnection accepts the Black Start Service revenue requirements submitted by the Black Start Service generator owner in such case, the Market Monitoring Unit may petition the Commission for an order that would require the Black Start Service generator to utilize the values determined by the Market Monitoring Unit or such other values as determined by the Commission. No change to a Black Start Service revenue requirement shall become effective until the existing revenue requirement has been effective for at least twelve months.

18. The formula for calculating a generator's annual Black Start Service revenue requirement is:

{(Fixed BSSC) + (Variable BSSC) + (Training Costs) + (Fuel Storage Costs)} * (1 + Z)

For units that have the demonstrated ability to operate at reduced levels when automatically disconnected from the grid, the formula is revised to:

(Training Costs) * (1+ Z)

where:

Fixed BSSC

Black Start Units with a commitment established under *Paragraph* 5 shall calculate Fixed BSSC or "Fixed Black Start Service Costs" in accordance with the following *Base Formula Rate*:

Base Formula Rate:

***Net* CONE * Black Start Unit Capacity * X**

Where:

"*Net* CONE" is the then current *installed capacity ("ICAP")* net Cost of New Entry *(expressed in $/MW year)* for the CONE Area where the Black Start Unit is located.

"Black Start Unit Capacity" is the Black Start Unit's installed capacity, expressed in MW.

"X" is the Black Start Service allocation factor unless a higher or lower value is supported by the documentation of the actual costs of providing Black Start Service. For such units qualifying as Black Start Units on the basis of demonstrated ability to operate at reduced levels when automatically disconnected from the grid, X shall be zero. For Black Start Units with a commitment established under section 5, X shall be .01 for Hydro units, .02 for Diesel or CT units.

Black Start Units with a commitment established under *Paragraph* 6 above shall calculate Fixed BSSC or "Fixed Black Start Service Costs" in accordance with *one of* the following formulas*, as applicable*:

Capital Cost Recovery Rate – NERC-CIP Specific Recovery

*(Net Cone * Black Start NERC-CIP Unit Capacity * X) + (Incremental Black Start NERC-CIP Capital Costs * CRF)*

Where:

"Net Cone" is the then current installed capacity ("ICAP") net Cost of New Entry (expressed in $/MW year) for the CONE are where the Black Start Unit is located.

"Black Start NERC-CIP Unit Capacity" is the Black Start Unit's installed capacity, expressed in MW, but, for purposes of this calculation, capped at 100 MW for Hydro units, or 50 MW for Diesel or CT units.

"Incremental Black Start NERC-CIP Capital Cost" are those capital costs documented by the owner or accepted by the Commission for the incremental equipment solely necessary to enable a Black Start Unit to maintain compliance with mandatory Critical Infrastructure Protection Reliability Standards (as approved by the Commission and administered by the applicable Electric Reliability Organization).

"CRF" or "Capital Recovery Factor" is equal to the levelized CRF as set forth in the applicable CRF Table set forth below.

A Black Start Unit may elect to terminate forward cost recovery under this Capital Cost Recovery Rate – NERC-CIP Specific Recovery at any time and seek cost recovery under the Capital Cost Recovery Rate, pursuant to the terms and conditions set forth below.

Capital Cost Recovery Rate

*(FERC-approved rate) + (Incremental Black Start Capital Costs * CRF)*

Where:

"FERC-approved rate" is the Black Start Unit's current FERC-approved recovery of costs to provide Black Start Service, if applicable.

"*Incremental* Black Start Capital Costs" *are* the *new or additional* capital cost*s* documented by the owner or accepted by the Commission for the incremental equipment solely necessary to enable a unit to provide Black Start Service in addition to whatever other product or services such unit may provide. Such costs shall include those incurred by a Black Start Owner in order to meet NERC Reliability Standards that apply to Black Start Units solely on the basis of the provision of Black Start Service by such unit. *However, Incremental Black Start Capital Costs shall not include any capital costs that the Black Start Unit owner is recovering for that unit pursuant to a FERC-approved recovery rate.*

"CRF" or "Capital Recovery Factor " is equal to the levelized CRF based on the age of the Black Start Unit, which is modified to provide Black Start Service, as present in the CRF Table *below*:

Age of Black Start Unit	*Term of Black Start Commitment*	Levelized CRF
1 to 5	20	0.125
6 to 10	15	0.146
11 to 15	10	0.198
16+	5	0.363

Or:

Optionally, a Black Start Unit owner may elect to apply an alternative Capital Recovery Factor, in lieu of the age-based CRF Table listed above, which is based upon to the expected Capital Improvement Lifespan of the new or additional capital improvements (as determined by the applicable depreciation period of the capital improvement, as published from time to time by the US Internal Revenue Service). The applicable term of Black Start Service commitment shall be equal to the Capital Improvement Lifespan. In the event that the Black Start Unit seeks recovery of capital improvements that are included in more than one category of Capital Improvement Lifespan (as set forth below), its applicable commitment to provide black start service for such Black Start Unit shall be the longest expected life of those new or additional capital improvements.

Capital Improvement Lifespan (Years)	*Levelized CRF*
16-20	*0.125*
11-15	*0.146*
6-10	*0.198*

1-5	*0.363*

In those circumstances where a Black Start Unit owner has elected to recover Incremental Black Start Capital Costs, in addition to a FERC-approved recovery rate, its applicable term of commitment shall be the greater of: (i) the FERC-approved recovery period, or; (ii) the applicable term of commitment as established by the CRF Tables above.

A Black Start Unit may make a non-revocable election to forego calculation of its Fixed BSSC, and surrender any forward compensation that it otherwise would have been entitled to, in accordance with either Capital Cost Recovery Rate set forth above. In this case, the Black Start Unit shall calculate its Fixed BSSC in accordance with the Base Formula Rate (and provide the applicable term of commitment established in Paragraph 5 above). In the event that the Black Start Unit seeks to recover further new or additional Black Start Capital Costs, it may not seek to recover any portion of those Black Start Capital Costs as its Fixed BSSC that it had previously forfeited.

After a Black Start Unit has recovered its allowable Incremental Black Start Capital Costs or Incremental Black Start NERC-CIP Capital Costs, as provided by the applicable Capital Cost Recovery Rate, and has satisfied its applicable commitment period required under Paragraph 6, the Black Start Unit shall be committed to providing black start in accordance with Paragraph 5 of this Schedule 6A and calculate its Fixed BSSC in accordance with the Base Formula Rate.

Variable BSSC

All Black Start Units shall calculate Variable BSSC or "Variable Black Start Service Costs" in accordance with the following formula:

Black Start Unit O&M * Y

Where:

"Black Start Unit O&M" are the operations and maintenance costs attributable to supporting Black Start Service and must equal the annual variable O&M outlined in the PJM Cost Development *Guidelines set forth in the PJM Manuals*. Such costs shall include those incurred by a Black Start Owner in order to meet NERC Reliability Standards that apply to the Black Start Unit solely on the basis of the provision of Black Start Service by unit.

"Y" is 0.01, unless a higher or lower value is supported by the documentation of costs. If a value of Y is submitted for this cost, a (1-Y) factor must be applied to the Black Start Unit's O&M costs on the unit's cost-based energy schedule, calculated based on the Cost *Development* Guidelines in the PJM *Manuals*.

For units qualifying as Black Start Units on the basis of a demonstrated ability to operate at reduced levels when automatically disconnected from the grid, there are no variable

costs associated with providing Black Start Service and the value for Variable BSSC shall be zero.

Training Costs:

All Black Start Units shall calculate Training Costs in accordance with the following formula:

50 staff hours/year/plant*75/hour

Fuel Storage Costs:

Black Start Units that cannot use oil for fuel shall *calculate* Fuel Storage Costs or "FSC" as zero. Black Start Units that can use oil for fuel shall calculate Fuel Storage Costs in accordance with the following formula:

{MTSL + [(# Run Hours) * (Fuel Burn Rate)]} *
(12 Month Forward Strip + Basis) * (Bond Rate)Where:

Run Hours are the actual number of hours a Transmission Provider requires a Black Start Unit to run. Run Hours shall be at least 16 hours or as defined by the Transmission Owner restoration plan, whichever is less.

"Fuel Burn Rate" is actual fuel burn rate for the Black Start Unit.

"12-Month Forward Strip" is the average of forward prices for the fuel burned in the Black Start Unit.
"Basis" is the transportation costs from the location referenced in the forward price data to the Black Start Unit plus any variable taxes.
"Bond rate" is the value determined with reference to the Moody's Utility Index for bonds rated Baa1.
"MTSL" is the "minimum tank suction level" and shall apply where no direct current pumps are available for the Black Start Unit.

For units qualifying as Black Start Units on the basis of a demonstrated ability to operate at reduced levels when automatically disconnected from the grid, there are no associated fuel storage costs and the value for FSC shall be zero.

Z

Z shall be an incentive factor for Black Start Units with a commitment established under section 5 above and shall be ten percent.

At least every two years, PJM shall review the formula and its costs components set forth in this section, and report on the results of that review to stakeholders.

19. Transmission Provider or its agent shall have the right to independently audit the accounts and records of each Black Start Unit that is receiving payments for providing Black Start Service.

20. PJM shall notify its Members when a Black Start Unit seeks to recover new or additional Black Start NERC-CIP Capital Costs under Paragraph 18 no later than thirty (30) days prior to the effective date of the recovery. At the written request of any PJM Member, made simultaneously to the Market Monitoring Unit and PJM, with notice to the Black Start Unit owner, the Market Monitoring Unit shall make available to the PJM Member for inspection at the offices of the Market Monitoring Unit, all data supporting the requested new or additional NERC-CIP specific Capital Costs. The Black Start Unit owner may elect to attend this review. In all cases, the supporting data is to be held confidential and may not be distributed.

21. The Market Monitoring Unit shall include a Black Start Service summary in its annual State of the Market report which will set forth a descriptive summary of the new or additional Black Start NERC-CIP Capital Costs requested by Black Start Units, and include a list of the types of capital costs requested and the overall cost of such capital improvements on an aggregate basis such that no data is attributable to an individual Black Start Unit.

Credits

22. Monthly credits are provided to generators that submit to the Transmission Provider their annual revenue requirements established pursuant to section 17 of this Schedule 6A. The generator's monthly credit is equal to 1/12 of its annual Black Start Service revenue requirement for eligible critical Black Start Units.

23. Revenue requirements for jointly owned Black Start Units will be allocated to the owners based on ownership percentage.

24. Transmission Provider shall not compensate generators for Black Start Service unless they meet the Transmission Provider and Applicable Regional Reliability Council criteria for Black Start Service and provide Transmission Provider with all necessary data in accordance with this Schedule 6A and the PJM manuals.

Charges

25. Zonal rates will be based on Black Start Service capability of generation units nominated by each transmission zone and allocated to network service customers and point-to-point reservations.

26. Revenue requirements for Black Start Units nominated by a Transmission Owner as critical (regardless of zonal location) will be allocated to the nominating Transmission Owner's zone.

27. Purchasers of Black Start Service shall be charged for such service in accordance with the following formulae.

Monthly Charge for a purchaser receiving Network Integration Transmission Service or Point-to-Point Transmission Service to serve Non-Zone Load = Allocation Factor * Total Generation Owner Monthly Black Start Service Revenue Requirement

Monthly Charge for a purchaser receiving Network Integration Transmission Service or Point-to-Point Transmission Service to serve Zone Load = Allocation Factor * Zonal Generation Owner Monthly Black Start Service Revenue Requirement * Adjustment Factor

Where:

Purchaser serving Non-Zone Load is a Network Customer serving Non-Zone Network Load or a Transmission Customer where the Point of Delivery is at the boundary of the PJM Region.

Zonal Generation Owner Monthly Black Start Service Revenue Requirement is the sum of the monthly Black Start Service revenue requirements for each generator nominated by the Transmission Owners in that zone.

Total Generation Owner Monthly Black Start Service Revenue Requirement is the sum of the Zonal Generation Owner Monthly Black Start Service Revenue Requirements for all Zones in the PJM Region.

Allocation Factor is the monthly transmission use of each Network Customer or Transmission Customer per Zone or Non-Zone, as applicable, on a megawatt basis divided by the total transmission use in the Zone or in the PJM Region, as applicable, on a megawatt basis.

For Network Customers, monthly transmission use on a megawatt basis is the sum of a Network Customer's daily values of DCPZ or DCPNZ (as those terms are defined in Section 34.1) as applicable, for all days of the month.

For Transmission Customers, monthly transmission use on a megawatt basis is the sum of the Transmission Customer's hourly amounts of Reserved Capacity for each day of~~in~~ the month (not curtailed by PJM) divided by the number of hours in the day~~24~~.

Adjustment Factor is determined as the sum of the total monthly transmission use in the PJM Region on a megawatt basis, exclusive of such use by Network Customers and Transmission Customers serving Non-Zone Load, divided by the total monthly transmission use in the PJM Region on a megawatt basis.

In the event that a single customer is serving load in more than one Zone, or serving Non-Zone Load as well as load in one or more Zones, or is both a Network Customer and a Transmission Customer, the Monthly Charge for such a customer shall be the sum of the Monthly Charges determined by applying the appropriate formulae set forth in this Schedule 6A.

ATTACHMENT K

Transmission Congestion and Loss Charges and Credits

Preface.

This Attachment and Attachment K – Appendix specifyies the manner in which all Transmission Customers, Network Customers, and Transmission Owners using the Transmission System to serve their Native Load Customers and Marker Participants submitting virtual bids and offers ~~(all of the foregoing being referred to as "Transmission Users"),~~ will be charged for the costs of congestion and losses on the Transmission System, ~~(as set forth in section A) and specifies~~ the manner in which all FTR holders share in the allocation of revenues received as Transmission Congestion Charges ~~(as set forth in section B).~~, and the manner in which Network Service Users, Market Participants in the PJM Interchange Energy Market and Transmission Customers share in the allocation of Transmission Loss Charges. ~~The provisions of this Attachment will apply to all Transmission Users, whether they are using the Transmission System for delivery of their own resources to load, for bilateral transactions, or to purchase or sell energy in the PJM Interchange Energy Market.~~ In addition, ~~the appendices to this~~ Attachment K - Appendix incorporates into the Tariff for ease of reference the provisions of Schedule 1 of the Operating Agreement ("Schedule 1"). Capitalized terms used in this Attachment which are not defined in the Tariff or in the Attachment, but which are defined in Schedule 1 shall have the meanings set forth in Schedule 1.

A. Transmission Congestion and Loss Charges

1. ~~General.~~[Reserved for Future Use]

~~Every Transmission User will be charged for the costs of congestion on the Transmission System on the basis of the difference between the Locational Marginal Price at the location or locations on the Transmission System where the Transmission User supplies energy for transmission and the location or locations where the Transmission User withdraws energy from the Transmission System. To implement these charges, the Office of the Interconnection will calculate credits for every Transmission User based on the Locational Marginal Price at the location or locations at which the Transmission System receives energy from the Transmission User, calculated in accordance with section A(2) of this Attachment, and will calculate debits based on the Locational Marginal Price at the location or locations to which the Transmission User uses the Transmission System to deliver energy, calculated in accordance with section A(3) of this Attachment. The difference, if any, between these credits and debits, less the Transmission User's net payments for purchases and sales in the PJM Interchange Energy Market, represents the Transmission Congestion Charges borne by the Transmission User. No additional Transmission Congestion Charges shall be assessed with respect to the Transmission User's sale or purchase of energy on the PJM Interchange Energy Market, because the price for the sale or purchase of such energy already reflects any differences between Locational Marginal Prices associated with the transaction.~~

2. ~~Credits to Transmission Users.~~ [Reserved for Future Use]

~~(a) For each hour during the day, each Transmission User shall be credited with the sum of the amounts determined in accordance with the following formula for each of the busses at which the Transmission User causes the Transmission System to receive electric energy:~~

~~Credit for Each Bus = Generation * Hourly LMP~~

~~where~~

~~Generation = The energy supplied by the Transmission User at the bus during the hour, measured in whole megawatts, as determined (i) in the case of a bus within the PJM Region, by the Office of the Interconnection utilizing the State Estimator model described in Section 2 of Schedule 1, and (ii) in the case of a bus at the border of such area, by the Transmission User's transaction request.~~

~~Hourly~~
~~LMP = the integrated hourly Locational Marginal Price (LMP) at the bus, calculated by the Office of the Interconnection based on five minute values; and~~

~~LMP = the cost to serve the next increment of load at the bus at the lowest possible price consistent with the preservation of reliability and transmission system conditions, determined as described in Section 2 of Schedule 1.~~

~~(b) Credits shall be calculated in accordance with subsection (a) for each generation bus in the PJM Region and for each bus representing an interconnection between such area and an adjacent control area. The total of the amounts determined in accordance with subsection (a) for all of the locations at which a Transmission User supplies energy for receipt by the Transmission System shall be summed for that Transmission User.~~

3. ~~Debits to Transmission Users.~~[Reserved for Future Use]

~~(a) For each hour during the day, each Transmission User shall be debited the sum of the amounts determined in accordance with the following formula for each of the busses to which the Transmission System delivers electric energy for the Transmission User:~~

~~Debit for Each Bus = (Load) * Hourly LMP~~

~~where~~

~~Load = the load at the bus during the hour, measured in whole megawatts, determined: (i) in the case of a bus within the PJM Region, by the Office of the Interconnection utilizing the State Estimator model described in Section 2 of Schedule 1 and the portion of such load at the bus attributable to the Transmission User; or (ii) in the case of a bus at the border of such area, by the Transmission User's transaction request;~~

~~Hourly~~
~~LMP = The integrated hourly Locational Marginal Price (LMP) at the bus, calculated by the Office of the Interconnection based on five minute values; and~~

~~LMP = The cost to serve the next increment of load at the bus at the lowest possible price consistent with the preservation of reliability and transmission system conditions, determined as described in Section 2 of Schedule 1.~~

~~(b) Debits shall be calculated in accordance with subsection (a) for each load bus in the PJM Region and for each bus representing an interconnection between such area and an adjacent control area. The total of the amounts determined in accordance with subsection (a) for all of the locations at which a Transmission User receives energy delivered by the Transmission System shall be summed for that Transmission User.~~

4. ~~Offset of Credits and Debits to a Transmission User.~~

In determining the total billable amount of Transmission Congestion Charges, ~~T~~the Office of the Interconnection, on behalf of PJMSettlement, shall take into account and set-off against each other both positive Transmission Congestion Charges and negative Transmission Congestion Charges ~~amounts credited to a Transmission User~~ in accordance with Section 5 of ~~A(2) of this~~ Attachment K – Appendix~~and amounts debited to a Transmission User in accordance with Section A(3) of this Attachment,~~. ~~and~~ PJMSettlement shall exclude ~~the Transmission User's~~ transactions on the PJM Interchange Energy Market~~,~~ in issuing a statement, invoice, or payment for the net amount owed ~~to or by that Transmission User~~ for Transmission Congestion Charges for any period.

In determining the total billable amount of Transmission Loss Charges, the Office of the Interconnection, on behalf of PJMSettlement, shall take into account and set-off against each other both positive Transmission Loss Charges and negative Transmission Loss Charges in accordance with Section 5 of Attachment K – Appendix. PJMSettlement shall exclude transactions on the PJM Interchange Energy Market in issuing a statement, invoice, or payment for the net amount owed for Transmission Loss Charges for any period.

B. Transmission Congestion and Loss Credits.

1. ~~General.~~

Financial Transmission Rights may be acquired by purchase in the Financial Transmission Rights auctions or in the secondary market provided for in Section 7 of Attachment K - Appendix. ~~The Office of the Interconnection will post information on the OASIS regarding FTR auction results, FTR transfers, including which FTRs have been transferred, the amount of the transfer (MW), the duration of the transfer and the identity of the buyer and seller.~~

~~For a new PJM zone, each Transmission Customer purchasing Firm Point-to-Point Service, each Network Customer, with respect to its reservation of firm transmission service for deliveries from Network Resources to Network Load, and each Transmission Owner with respect to its reservation of firm transmission service for the delivery of energy from Generation Capacity Resources to Native Load Customers (any of the foregoing being referred to as a "Firm Transmission User"), shall receive Financial Transmission Rights ("FTRs") corresponding to points of receipt and delivery designated for their firm uses of the Transmission System. Such FTRs shall remain in effect until the first annual allocation of Auction Revenue Rights to occur after the integration of such new PJM zone into the PJM Interchange Energy Market.~~

Each holder of an FTR shall receive the total Transmission Congestion Credits determined in accordance with Section 5~~B(2)~~ of ~~this~~ Attachment K - Appendix.

Each Network Service User and Transmission Customer shall receive an allocation of Transmission Loss Credits in accordance with Section 5 of Attachment K – Appendix.

2 ~~Determination of Credit.~~[Reserved for Future Use]

~~(a) **Overview.** For each hour with respect to which the Transmission Provider receives payments of Transmission Congestion Charges, determined in accordance with section A of this Attachment, Transmission Congestion Credits shall be allocated to the holders of Financial Transmission Rights. As explained in subsection B(1) above, the Financial Transmission Rights are associated with the points on the Transmission System between which the Firm Transmission User to whom the FTR was originally issued has arranged for the firm transmission of electric energy, whether on a network or point-to-point basis. Holders of FTRs receive credits attributable to the difference, if any, between Congestion Prices at the Point or Points of Receipt and the Point or Points of Delivery associated with the Financial Transmission Rights. As explained in Section 5.2.2 of Attachment K – Appendix, each FTR holder shares in Transmission Congestion Credits to the extent it holds Financial Transmission Rights between the Point or Points of Receipt and the Point or Points of Delivery at which congestion is experienced in a particular hour. Distribution of credits in this manner ensures that each FTR holder will not incur energy costs that are greater than the costs of energy from the generation resources associated with the FTR holder's Financial Transmission Rights. Target allocations of Transmission Congestion Credits to holders of Financial Transmission Rights are calculated in accordance with Section 5.2.5 of Attachment K – Appendix and Transmission Congestion Credits are distributed in accordance with that allocation, as described in Sections 5.2.5 and 5.2.6 of Attachment K – Appendix.~~

~~(b) **Assignment of Financial Transmission Rights.** Financial Transmission Rights shall be obtained pursuant to Attachment K - Appendix.~~

~~(c) **Assignment of Auction Revenue Rights.** Auction Revenue Rights shall be assigned pursuant to Attachment K - Appendix.~~

~~(d) **Target Allocation of Credits to Financial Transmission Rights.** Target Allocation of Transmission Congestion Credits for each FTR holder for each hour shall be pursuant to Attachment K – Appendix.~~

~~(e) **Distribution of Transmission Congestion Credits.** Distribution of Transmission Congestion Credits shall be pursuant to Attachment K – Appendix.~~

C. [Reserved for Future Use]~~Offset of Transmission Congestion Charges and Transmission Congestion Credits.~~

~~The Office of the Interconnection, on behalf of PJMSettlement, shall take into account both (i) amounts payable by a Transmission User with respect to Transmission Congestion Charges as determined in accordance with Section A of this Attachment, and (ii) amounts payable to a Transmission User with respect to Transmission Congestion Credits as determined in accordance with Section B of this Attachment.~~

D. Transmission Service Components.

Transmission Congestion Charges, ~~and~~ Transmission Congestion Credits, Ancillary Services charges and credits, Transmission Loss Charges, Transmission Loss Credits and allocations of Financial Transmission Rights auction revenues ~~to a Transmission User~~ are components of transmission service charges under Parts II and III of the Tariff and shall not give rise to separate transactions with PJMSettlement regarding the purchase or sale of electric energy.

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 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) In the Real-time Energy Market, Market Participants that deviate from the amounts of energy purchases or sales, or Transmission Customers that deviate from the transmission uses, scheduled in the Day-ahead Energy Market shall be obligated to purchase or sell energy, or 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.

(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 shall be conducted as specified 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.

1.10.1A Day-Ahead Energy Market Scheduling.

The following actions shall occur not later than 12:00 noon 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.

(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 bilateral transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection whether the transaction is to be included in the Day-ahead Energy Market. Any Market Participant that elects to include a bilateral transaction in the Day-ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the PJM Manuals), if any, at which it will be wholly or partially curtailed rather than pay Transmission Congestion Charges. The foregoing price specification shall apply to the price difference between the specified bilateral transaction source and sink points in the day-ahead scheduling process only. Any Market Participant that elects not to include its bilateral 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 Charges in the Real-time Energy Market in order to complete any such scheduled bilateral transaction. Scheduling of bilateral transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

i) Internal Market Buyers shall submit schedules for all bilateral purchases for delivery within the PJM Region, whether from generation resources inside or outside the PJM Region;

ii) Market Sellers shall submit schedules for bilateral sales to entities outside the PJM Region from generation within the PJM Region that is not dynamically scheduled to such entities pursuant to Section 1.12; and

iii) In addition to the foregoing schedules for bilateral transactions, Market Participants shall submit confirmations of each scheduled bilateral transaction from each

other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(d) Market Sellers wishing to sell into the Day-ahead Energy Market shall submit offers for the supply of energy (including energy from hydropower units), demand reductions, Regulation, Operating Reserves or other services for the following 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(d), Schedule 2 of the Operating Agreement, and the PJM Manuals, as applicable. 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 Attachment DD of the PJM Tariff, 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. The submission of offers for resource increments that have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, and PJM Manuals, as applicable. Energy offered from generation resources that have not cleared a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff 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 Demand Resource and energy or demand reduction amount, respectively, for each hour in the offer period, and the minimum run time for generation resources and minimum down time for Demand Resources;

ii) Shall specify the amounts and prices for the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;

iii) If based on energy from a specific generating unit, may specify start-up and no-load fees equal to the specification of such fees for such unit on file with the Office of the Interconnection, if based on reductions in demand from a Demand Resource may specify shutdown costs;

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 a second schedule 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, which offer shall remain open through the Operating Day for which the offer is submitted;

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; and

viii) Shall not exceed an energy offer price of $1,000/megawatt-hour.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation that shall specify the megawatt of Regulation being offered, which must equal or exceed 0.1 megawatts, the Regulation Zone for which such regulation is offered, the price of the offer in dollars per MWh, 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. The price of the offer shall not exceed $100 per MWh in the case of Regulation offered for all Regulation Zones. 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 heat rate increase resulting from operating a unit at lower megawatt output incurred from the provision of Regulation;

ii. The cost increase (in $/MW) in variable operating and maintenance costs resulting from operating the unit at lower megawatt output incurred from the provision of Regulation; and

iii. An adder of up to $12.00 per megawatt of Regulation provided.

Qualified Regulation capability must satisfy the 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 and no-load fees, 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.

(g) Each offer by a Market Seller of a Generation Capacity Resource shall remain in effect for subsequent Operating Days until superseded or canceled.

(h) The Office of the Interconnection shall post ~~on the PJM Open Access Same-time Information System~~ 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 Increment Bids and/or Decrement Bids that apply to the Day-ahead Energy Market only. Such bids 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 3000 bid/offer segments in the Day-ahead Energy Market, 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 Bid or Decrement Bid.

(j) A Market Seller that wishes to make a generation resource or Demand Resource available to sell Synchronized Reserve shall submit an offer for Synchronized Reserve that shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.1 megawatts, the price of the offer in dollars per megawatt hour, and such other information specified by the Office of Interconnection as may be necessary to evaluate the offer and the energy used by the generation resource to provide the Synchronized Reserve and the generation resource's unit specific opportunity costs. The price of the offer shall not exceed the variable operating and maintenance costs for providing Synchronized Reserve plus seven dollars and fifty cents.

(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. The offer must equal or exceed 0.1 megawatts, and the offer 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; and (iii) at the Economic Load Response Participant's option, start-up 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. 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).

(l) Market Sellers owning or controlling the output of a Demand Resource that was committed in an FRR Capacity Plan, self-supplied or offered and cleared in the Base Residual Auction or one of the Incremental Auctions, or owning or controlling the output of an ILR resource which was certified as specified in Attachment DD of the PJM Tariff, may submit demand reduction bids for the available load reduction capability of the Demand Resource or ILR resource. The submission of demand reduction bids for resource increments that have not cleared in the Base Residual Auction or in one of the Incremental Auctions, or for ILR resources that were not certified, or were not committed in an FRR Capacity Plan, shall be optional, but any such bids must contain the information specified in the PJM Economic Load Response Program to be included in such bids. A Demand Resource that was committed in an FRR Capacity plan, self-supplied or offered and cleared in a Base Residual Auction or an 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 Demand Resources and ILR 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) Market Sellers that wish to make Day-ahead Scheduling Reserves Resources available to sell Day-ahead Scheduling Reserves shall submit offers, each of which must equal or exceed 0.1 megawatts, in the Day-ahead Scheduling Reserves Market specifying: 1) the price of the offer in dollars per megawatt hour; and 2) such other information specified by the Office of the Interconnection as may be necessary to determine any relevant opportunity costs for the resource(s). The foregoing notwithstanding, to qualify to submit offers pursuant to this section, the Day-ahead Scheduling Reserves Resources shall submit energy offers in the Day-ahead Energy Market including start-up and shut-down costs for generation resource and Demand Resources, respectively, and all generation resources that are capable of providing Day-ahead Scheduling Reserves that a particular resource can provide that service. The MW quantity of Day-Ahead Scheduling Reserves that a particular resource can provide in a given hour will be determined based on the energy Offer Data submitted in the Day-ahead Energy Market, as detailed in the PJM Manuals.

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 Sections 1.10.9 or 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, start-up, no-load 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.

(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 and no-load fees, from the Office of the Interconnection on behalf of the Market Buyers in accordance with Section 3 of this Schedule 1. Alternatively, the Market Seller shall receive, in lieu of start-up and no-load fees, its actual costs incurred, if any, up to a cap of the resource's start-up cost, 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 offer must equal or exceed 0.1 megawatts, in minimum increments of .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 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, or otherwise not following the dispatch orders of 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.

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.

(c) A resource that has been self-scheduled shall not receive payments or credits for start-up or no-load fees.

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 dispatch 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. ~~If a Market Seller submits more than one offer on an aggregated resource basis, the withdrawal of any such offer shall be deemed a withdrawal of all higher priced offers for the same period.~~

(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 dispatch by the Office of the Interconnection shall be delivered on a block loaded basis to the ~~load~~ bus or busses 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) ~~or credited~~ at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing ~~load~~ bus or busses.

(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.

1.10.6A Transmission Loading Relief Customers.

(a) An entity that desires to elect to pay Transmission Congestion Charges in order to continue its energy schedules during an Operating Day over contract paths outside the PJM Region in the event that PJM initiates Transmission Loading Relief that otherwise would cause PJM to request security coordinators to curtail such Member's energy schedules shall:

(i) enter its election on OASIS by 12:00 p.m. of the day before the Operating Day, in accordance with procedures established by PJM, which election shall be applicable for the entire Operating Day; and

(ii) if PJM initiates Transmission Loading Relief, provide to PJM, at such time and in accordance with procedures established by PJM, the hourly integrated energy schedules that impacted the PJM Region (as indicated from the NERC Interchange Distribution Calculator) during the Transmission Loading Relief.

(b) If an entity has made the election specified in Section (a), then PJM shall not request security coordinators to curtail such entity's energy transactions, except as may be necessary to respond to Emergencies.

(c) In order to make elections under this Section 1.10.6A, an entity must (i) have met the creditworthiness standards established by the Office of the Interconnection or provided a letter of credit or other form of security acceptable to the Office of the Interconnection, and (ii) have executed either the Agreement, a Service Agreement under the PJM Tariff, or other agreement committing to pay all Transmission Congestion Charges incurred under this Section.

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 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; (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 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) Not earlier ~~later~~ than 4:00 p.m. of the day before each Operating Day, or such other ~~earlier~~ 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.

(c) Following posting of the information specified in Section 1.10.8(b), 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. ~~The Office of the Interconnection shall post on the PJM Open Access Same-time Information System at times specified in the PJM Manuals a revised forecast of the location and duration of any expected transmission congestion, and of the range of differences in Locational Marginal Prices between major subareas of the PJM Region expected to result from such transmission congestion.~~

(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 offer that set 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 offer that set the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Section 3.3A of this Schedule.

(e) If the Office of the Interconnection discovers an error in prices and/or cleared quantities in the Day-ahead Energy Market, Real-time Energy Market, Ancillary Services Markets or Day Ahead Scheduling Reserve Market after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants of the error 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 Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the second business day following the initial publication of the results for the Day-ahead Scheduling Reserve Market and Day-ahead Energy Market.

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, together with all available supporting documentation, by no later than 5:00 p.m. of the fifth business day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the fifth business day following the initial publication of the results in the Day-ahead Scheduling Reserve Market and the Day-ahead Energy Market. 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 Ancillary Services Markets, Day-ahead Energy Market and Real-time Energy Market, and no later than 5:00 p.m. of the tenth calendar day following the initial publication of the results in the Day-ahead Scheduling Reserve Market. 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 Section 18.17.1 of the PJM Operating Agreement, 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, a generation rebidding period shall exist from 4:00 p.m. to 6:00 p.m. on the day before each Operating Day. During the rebidding period, Market Participants may submit revisions to generation Offer Data for any generation resource that was not selected as a pool-scheduled resource in the Day-ahead Energy Market. Adjustments to Day-ahead Energy Markets 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 10:00 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 60 minutes prior to the hour in which the adjustment is to take effect, as follows:

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 fee.

(c) With respect to a pool-scheduled resource that is included in the Day-ahead Energy Market, a Market Seller may not change or otherwise modify its offer to sell energy.

(d) 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 60 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.

(e) 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.

1.11 Dispatch.

The following procedures and principles shall govern the dispatch of the resources available to the Office of the Interconnection.

1.11.1 Resource Output.

The Office of the Interconnection shall have the authority to direct any Market Seller to adjust the output of any pool-scheduled resource increment within the operating characteristics specified in the Market Seller's offer. The Office of the Interconnection may cancel its selection of, or otherwise release, pool-scheduled resources, subject to an obligation to pay any applicable start-up, no-load or cancellation fees. The Office of the Interconnection shall adjust the output of pool-scheduled resource increments as necessary: (a) to maintain reliability, and subject to that constraint, to minimize the cost of supplying the energy, reserves, and other services required by the Market Buyers and the operation of the PJM Region; (b) to balance load and generation, maintain scheduled tie flows, and provide frequency support within the PJM Region; and (c) to minimize unscheduled interchange not frequency related between the PJM Region and other Control Areas.

1.11.2 Operating Basis.

In carrying out the foregoing objectives, the Office of the Interconnection shall conduct the operation of the PJM Region in accordance with the PJM Manuals, and shall: (i) utilize available generating reserves and obtain required replacements; and (ii) monitor the availability of adequate reserves.

1.11.3 Pool-dispatched Resources.

(a) The Office of the Interconnection shall implement the dispatch of energy from pool-scheduled resources with limited energy by direct request. In implementing mandatory or economic use of limited energy resources, the Office of the Interconnection shall use its best efforts to select the most economic hours of operation for limited energy resources, in order to make optimal use of such resources consistent with the dynamic load-following requirements of the PJM Region and the availability of other resources to the Office of the Interconnection.

(b) The Office of the Interconnection shall implement the dispatch of energy from other pool-dispatched resource increments, including generation increments from Capacity Resources the remaining increments of which are self-scheduled, by sending appropriate signals and instructions to the entity controlling such resources, in accordance with the PJM Manuals. Each Market Seller shall ensure that the entity controlling a pool-dispatched resource offered or made available by that Market Seller complies with the energy dispatch signals and instructions transmitted by the Office of the Interconnection.

1.11.3A Maximum Generation Emergency.

If the Office of the Interconnection declares a Maximum Generation Emergency, all deliveries to load that is served by Point-to-Point Transmission Service outside the PJM Region from Generation Capacity Resources committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative may be interrupted in order to serve load in the PJM Region.

1.11.4 Regulation.

(a) A Market Buyer may satisfy its Regulation Obligation from its own generation resources and/or Demand Resources capable of performing Regulation service, by contractual arrangements with other Market Participants able to provide Regulation service, or by purchases from the PJM Interchange Energy Market at the rates set forth in Section 3.2.2. PJMSettlement shall be the Counterparty to the purchases and sales of Regulation service in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Regulation Obligation.

(b) The Office of the Interconnection shall obtain Regulation service from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Demand Resources as needed to meet Regulation Zone requirements not otherwise satisfied by the Market Buyers. Generation resources or Demand Resources offering to sell Regulation shall be selected to provide Regulation on the basis of each generation resource's and Demand Resource's regulation offer and the estimated opportunity cost of a resource providing regulation and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Regulation, and other ancillary services. Estimated opportunity costs for generation resources shall be determined by the Office of the Interconnection on the basis of the expected value of the energy sales that would be foregone or uneconomic energy that would be produced by the resource in order to provide Regulation, in accordance with procedures specified in the PJM Manuals. Estimated opportunity costs for Demand Resources will be zero. ~~If the Office of the Interconnection is not able to distinguish resources offering Regulation on the basis of their regulation offers and estimated opportunity costs, resources shall be selected on the basis of the quality of Regulation provided by the resource as determined by tests administered by the Office of the Interconnection.~~

(c) The Office of the Interconnection shall dispatch resources for Regulation by sending Regulation signals and instructions to generation resources and/or Demand Resources from which Regulation service has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall comply with Regulation dispatch signals and instructions transmitted by the Office of the Interconnection and, in the event of conflict, Regulation dispatch signals and instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their resources supplying load in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4A Synchronized Reserve.

(a) A Market Buyer may satisfy its Synchronized Reserve obligation from its own generation resources and/or Demand Resources capable of providing Synchronized Reserve, by contractual arrangements with other Market Participants able to provide Synchronized Reserve, or by purchases from the PJM Synchronized Reserve Market at the rates set forth in Section 3.2.3A. PJMSettlement shall be the Counterparty to the purchases and sales of Synchronized Reserve in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Synchronized Reserve Obligation.

(b) The Office of the Interconnection shall obtain Synchronized Reserve from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Demand Resources as needed to meet the Synchronized Reserve requirements of each Synchronized Reserve Zone of the PJM Region not otherwise satisfied by the Market Buyers. Resources offering to sell Synchronized Reserve shall be selected to provide Synchronized Reserve on the basis of each generation resource's and/or Demand Resource's Synchronized Reserve offer and the estimated unit specific opportunity cost of the resource providing Synchronized Reserve, and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Synchronized Reserve and other ancillary services. Estimated unit specific opportunity costs for generation resources shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the generation resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to 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, times (B) the absolute value of 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 Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources will be zero.

(c) The Office of the Interconnection shall dispatch generation resources and/or Demand Resources for Synchronized Reserve by sending Synchronized Reserve instructions to generation resources and/or Demand Resources from which Synchronized Reserve has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall comply with Synchronized Reserve dispatch instructions transmitted by the Office of the Interconnection and, in the event of a conflict, Synchronized Reserve dispatch instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their generation resources supplying load in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.5 PJM Open Access Same-time Information System.

The Office of the Interconnection shall update the information posted on the PJM Open Access Same-time Information System to reflect its dispatch of generation resources.

3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

(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 Section 2 of this Schedule

(b) Market Buyers shall be charged for all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price .

(c) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(d) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the total amount of net hourly PJM Interchange for each Market Buyer, including Generating Market Buyers, in accordance with the PJM Manuals. For Internal Market Buyers that are Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall include determination of the net energy flows from: (i) tie lines; (ii) any generation resource the output of which is controlled by the Market Buyer but delivered to it over another entity's Transmission Facilities; (iii) any generation resource the output of which is controlled by another entity but which is directly interconnected with the Market Buyer's transmission system; (iv) deliveries pursuant to bilateral energy sales; (v) receipts pursuant to bilateral energy purchases; and (vi) an adjustment to account for the day-ahead PJM Interchange, calculated as the difference between scheduled withdrawals and injections by that Market Buyer in the Day-ahead Energy Market. For External Market Buyers and Internal Market Buyers that are not Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall determine the energy scheduled hourly for delivery to the Market Buyer net of the amounts scheduled by such ~~the External~~ Market Buyer in the Day-ahead Energy Market.

(e) An Internal Market Buyer shall be charged for Spot Market Energy purchases to the extent of its hourly net purchases from the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. An External Market Buyer shall be charged for its Spot Market Energy purchases based on the energy delivered to it, determined as specified in Section 3.2.1(d) above. The total charge shall be determined by the product of the hourly net amount of PJM Interchange Imports times the hourly Real-time System Energy Price for that Market Buyer.

(f) A Generating Market Buyer shall be paid as a Market Seller for sales of Spot Market Energy to the extent of its hourly net sales into the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. The total payment shall be determined by the product of the hourly net amount of PJM Interchange Exports times the hourly Real-time System Energy Price for that Market Seller.

3.2.2 Regulation.

(a) Each Internal Market Buyer 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 requirements of such Regulation Zone for the hour, based on the Market Buyer'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"). An Internal Market Buyer that does not meet its hourly Regulation obligation shall be charged for Regulation dispatched by the Office of the Interconnection to meet such obligation at the Regulation market-clearing price determined in accordance with subsection (c) of this section, plus the amounts, if any, described in subsection (f) of this section.

(b) A Generating Market Buyer supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection in excess of its hourly Regulation obligation shall be credited for each increment of such Regulation at the higher of (i) the Regulation market-clearing price in such Regulation Zone or (ii) the sum of the regulation offer and the unit-specific opportunity cost of the generation resource supplying the increment of Regulation, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Regulation market-clearing price in each Regulation Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day. The market-clearing price for each regulating hour shall be equal to the highest sum of a resource's Regulation offer plus its estimated unit-specific opportunity costs, determined as described in subsection (d) below from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.3.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation market-clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour shall be equal to the sum of the unit-specific opportunity costs (i) incurred during the hour in which the obligation is fulfilled, plus costs (ii) associated with uneconomic operation during the hour preceding the initial regulating hour ("preceding shoulder hour"), plus costs (iii) associated with uneconomic operation during the hour after the final regulating hour ("following shoulder hour").

The unit-specific opportunity costs incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (a) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the resource's expected output during the preceding shoulder hour, times (b) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource during the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (c) the percentage of the preceding shoulder hour during which the deviation was incurred.

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (a) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the resource's expected output in the following shoulder hour, times (b) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (c) the percentage of the following shoulder hour that the deviation was incurred.

Estimated opportunity costs for Demand Resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Generating Market Buyer 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 each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's Regulation signals from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour 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 hour in order to

provide Regulation and the lesser of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, 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 the following shoulder hour 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 hour in order to provide Regulation and the lesser of the resource's actual or expected output in the following shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the following shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the following shoulder hour during which the deviation was incurred, 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 Internal Market Buyer 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.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to section 1.10.1A(e) of this Schedule. A Regulation supplier fails the three-pivotal supplier test in any hour 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 three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region for which the cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The 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.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the prices offered 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 Section 3.2.3A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, 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 Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load fees 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. Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. 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 from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), 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.

(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 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 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 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 in the Day-ahead Energy Market.

(d) The cost of Operating Reserves 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 (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; 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 dynamically scheduled to load outside such area pursuant to Section 1.12.

(e) 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~~, and that is not committed solely for the purpose of providing Synchronized Reserve:~~ 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 or minimum run time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or minimum run time (minimum down time for Demand 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 (minimum down time for Demand Resources) and Segment 2 will include the remainder of the contiguous hours 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.

Credits received pursuant to this section shall be equal to the positive difference between a resource's total offered price for start-up (shutdown costs for Demand Resources) and no-load fees and energy, determined on the basis of the resource's scheduled output, and the total value of the resource's energy as determined by the Real-time Energy Market and 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 Demand 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) plus the resource's opportunity cost and less any amounts credited for Synchronized Reserve in excess of the Synchronized Reserve offer plus the resource's opportunity cost and less any amounts credited for Reactive Services as specified in Section 3.2.3.B, and less any amounts for Day-ahead Scheduling Reserve in excess of the Day-ahead Scheduling Reserve offer plus the resource's opportunity cost, shall be credited to the Market Seller.

Synchronized Reserve and Day-ahead Scheduling Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding hour(s) in which the Synchronized Reserve and Day-ahead Scheduling Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each hour ~~period~~ the unit operates in condensing and generation mode ~~for one or more contiguous hours~~.

(f) A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool-scheduled (or self-scheduled, if operating according to 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 hourly integrated, 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 hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

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 hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

AG equals the actual hourly integrated output of the unit;

URTLMP equals the real time LMP at the unit's bus;

UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UB shall not be negative.

(f-1) A Market Seller's combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost 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 above for a steam unit or combined cycle unit operating in combined cycle mode.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG, or (ii) {(URTLMP – UB) x DAG where:

URTLMP equals the real time LMP at the unit's bus;

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit, determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

(f-2) A Market Seller's hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to 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~~A~~(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.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with 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, less any payments received from another Control Area for Operating Reserves, plus any redispatch costs incurred in accordance with section 10(a) of this Schedule, shall be 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 shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (i) load deviations (net of operating Behind The Meter Generation) from the Day-ahead Energy Market in megawatt-hours during that Operating Day, except as noted below and in the PJM Manuals; (ii) generation deviations (not including deviations in Behind The Meter Generation) from the Day-ahead Energy Market for non-dispatchable generation resources, including External Resources, in megawatt-hours during the Operating Day; (iii) deviations from the Day-ahead Energy Market for bilateral transactions from outside the PJM Region for delivery within such region in megawatt-hours during the Operating Day; and (iv) deviations of energy sales from the Day-ahead Energy Market 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 dynamically scheduled to load outside such area pursuant to Section 1.12.

Deviations that occur within a single Zone shall be associated with the Eastern or Western Regions, as defined in Section 3.2.3(q) of this Schedule, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with Section 3.2.3(q). Deviations at interfaces and hubs shall be associated with the Eastern or Western Region if all the busses that define all interfaces or all hubs are located in the region. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to 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 busses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed 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 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 an Operating Reserve shortage in real-time or where PJM initiates the request for load reductions in real-time in order to avoid an Operating Reserve shortage as described in this Schedule, Section 6A, Scarcity Pricing.

(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.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized 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 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 for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for ~~each Control Zone~~ of the PJM Region ~~based on the Control Zone to which the resource was synchronized to provide synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation~~.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized 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 (net of operating Behind The Meter Generation, but not to be less than zero) 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 dynamically scheduled to load outside ~~such Control Zone~~ the PJM Region pursuant to 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 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 Schedule 2 of the Operating Agreement, 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 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 Section 1.9.7(b); provided, however, that the Market Seller must return to compliance with 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, the Market Seller shall not receive any credit for Operating Reserves. 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 for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatt hours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours 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 hours 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 12:00 noon 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 not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon 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 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 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 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 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 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 generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described in the PJM Manuals. Ramp-limited desired MW values shall be used to determine generation resource real-time deviations from the resource's day-ahead schedules.

The Office of the Interconnection shall calculate a ramp-limited desired MW value for 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:

$$Ramp\_Request_t = \frac{(UDStarget_{t-1} - AOutput_{t-1})}{(UDSLAtime_{t-1})}$$

$$RL\_Desired_t = AOutput_{t-1} + \left(Ramp\_Request_t * Case\_Eff\_time_{t-1}\right)$$

where:

1. UDStarget = UDS basepoint for the previous UDS case
2. AOutput = Unit's output at case solution time
3. UDSLAtime = UDS look ahead time
4. Case_Eff_time = Time between base point changes
5. RL_Desired = Ramp-limited desired MW

To determine if a 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 UDS Basepoint or the actual output and ramp-limited desired MW value.

The % off dispatch and MW off dispatch will be a time-weighted average over the course of an hour. If the UDS Basepoint 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 UDS LMP Desired MW.

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 UDS Basepoint, or if its % off dispatch is <= 10, or it's hourly integrated Real-time MWh is within 5% or 5 MW (whichever is greater) of the hourly integrated 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 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: hourly integrated Real-time 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: hourly integrated Real-time MWh – UDS LMP Desired MW.

- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – hourly integrated 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 UDS LMP Desired MWh for the hour 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: hourly integrated Real time MWh – UDS 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: hourly integrated Real-time Mwh – hourly integrated Ramp-Limited Desired MW. If deviation value is within 5% or 5 MW (whichever is greater) 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: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch, and the resource has tripped, for the hour the resource tripped and the hours it remains offline throughout its day-ahead schedule

balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time 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: hourly integrated Real-time MWh and Day-Ahead MWh.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve 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 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 Operating Reserve charges shall be allocated to real-time deviations 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 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 Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing 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 Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed 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 charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category 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(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) 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 Region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, *DEOK* transmission Zones, and the Eastern 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:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve 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 reliability 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 Section 3.2.3(p).

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. 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 Section 3.2.3(p).

(iii) Reliability and deviation regional balancing Operating Reserve rates shall be determined by summing the relevant RTO balancing Operating Reserve 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.

3.2.3A Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Synchronized Reserve Zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Synchronized Reserve 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). An Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts if any, described in subsections (g), (h) and (i) of this section.

(b) A Generating Market Buyer supplying Synchronized Reserve at the direction of the Office of the Interconnection, in excess of its hourly Synchronized Reserve Obligation, shall be credited as follows:

i) Credits for Synchronized Reserve provided by generation units that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event ("Tier 1 Synchronized Reserve") shall be at the Synchronized Energy Premium Price.

ii) Credits for Synchronized Reserve provided by generation resources that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the Interconnection energy dispatch signals and instructions ("Tier 2 Synchronized Reserve") shall be the higher of (i) the Synchronized Reserve Market Clearing Price or (ii) the sum of (A) the Synchronized Reserve offer, and (B) the specific 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.

iii) Credits for Synchronized Reserve provided by Demand Resources that are synchronized to the grid and accept the obligation to reduce load in response to a synchronized Reserve Event initiated by the Office of the Interconnection shall be the sum of (i) the higher of (A) the Synchronized Reserve offer or (B) the synchronized Reserve Market Clearing Price and (ii) if a Synchronized Reserve Event is actually initiated by the Office of the Interconnection and the Demand Resource reduced its load in response to the event, the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

(c) The Synchronized Reserve Energy Premium Price is the average of the five-minute Locational Marginal Prices calculated during the Synchronized Reserve Event plus an

adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Synchronized Reserve Zone by the Office of the Interconnection prior to the operating hour and such market-clearing price shall be equal to, from among the generation resources or Demand Resources selected to provide Synchronized Reserve for such Synchronized Reserve Zone, the highest sum of either (i) a generation resource's Synchronized Reserve offer and opportunity cost or (ii) a demand response resource's Synchronized Reserve offer.

(e) In determining the Synchronized Reserve Market Clearing Price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the expected Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) ~~the absolute value of~~ the difference between the expected 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 Synchronized Reserve set 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. The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to 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, times (B) ~~the absolute value of~~ 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 Synchronized Reserve set point for the generation 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. The opportunity costs for a Demand Resource shall be zero.

(g) Charges for Tier 1 Synchronized Reserve will be allocated in proportion to the amount of Tier 1 Synchronized Reserve applied to each Synchronized Reserve Obligation. In the event Tier 1 Synchronized Reserve is provided by a Market Seller in excess of that Market Seller's Synchronized Reserve Obligation, the remainder of the Tier 1 Synchronized Reserve

that is not utilized to fulfill the Seller's obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

(h) Any amounts credited for Tier 2 Synchronized Reserve in an hour in excess of the Synchronized Reserve Market Clearing Price in that hour shall be allocated and charged to each Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation in proportion to its purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) In the event the Office of the Interconnection needs to assign more Tier 2 Synchronized Reserve during an hour than was estimated as needed at the time the Synchronized Reserve Market Clearing Price was calculated for that hour due to a reduction in available Tier 1 Synchronized Reserve, the costs of the excess Tier 2 Synchronized Reserve shall be allocated and charged to those providers of Tier 1 Synchronized Reserve whose available Tier 1 Synchronized Reserve was reduced from the needed amount estimated during the Synchronized Reserve Market Clearing Price calculation, in proportion to the amount of the reduction in Tier 1 Synchronized Reserve availability.

(j) In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled by the owner to provide Tier 2 Synchronized Reserve fails to provide the assigned or self-scheduled amount of Synchronized Reserve in response to an actual Synchronized Reserve Event, the owner of the resource shall incur an additional Synchronized Reserve Obligation in the amount of the shortfall for a period of three consecutive days with the same peak classification (on-peak or off-peak) as the day of the Synchronized Reserve Event at least three business days following the Synchronized Reserve Event. The overall Synchronized Reserve requirement for each Synchronized Reserve Zone of the PJM Region on which the Synchronized Reserve Obligations, except for the additional obligations set forth in this section, are based shall be reduced by the amount of this shortfall for the applicable three-day period.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l) is the difference between the generation resource's output or the Demand 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 Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand 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 a Demand Resource will be reduced by the amount the megawatt consumption of the Demand 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 Demand 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 Demand Resource's consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Demand 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.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJMSettlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

(b) A Day-ahead Scheduling Reserves Resource that receives a Day-ahead Scheduling Reserves schedule pursuant to subsection (a) of this section shall be paid the hourly Day-ahead Scheduling Reserves Market clearing price for the MW obligation in each hour of the schedule, subject to meeting the requirements of subsection (c) of this section.

(c) To be eligible for payment pursuant to subsection (b) of this section, Day-ahead Scheduling Reserves Resources shall comply with the following provisions:

(i) Generation resources with a start time greater than thirty minutes are required to be synchronized and operating at the direction of the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule and shall have a dispatchable range equal to or greater than the Day-ahead Scheduling Reserves schedule.

(ii) Generation resources and Demand Resources with start times or shut-down times, respectively, equal to or less than 30 minutes are required to respond to dispatch directives from the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule. To meet this requirement the resource shall be

required to start or shut down within the specified notification time plus its start or shut down time, provided that such time shall be less than thirty minutes.

(iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). 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 one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand 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 time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand 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 credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

Resources that do not comply with the provisions of this subsection (c) shall not be eligible to receive credits pursuant to subsection (b) of this section.

(d) The cost of credits allocated to Day-ahead Scheduling Reserves Resources pursuant to this section shall be charged to Load-Serving Entities in the PJM Region based on load ratio share (net of operating Behind The Meter Generation, but not to be less than zero), provided that a Load-Serving Entity may satisfy its Day-ahead Scheduling Reserves obligation, which is equal to the Day-ahead Scheduling Reserves Requirement multiplied by the Load-Serving Entity's load ratio share for the PJM Region, through one or any combination of the following: 1) the Day-ahead Scheduling Reserves Market; 2) and bilateral arrangements. The Day-ahead Scheduling Reserve charges allocated pursuant to this section shall reflect any portion of a Load-Serving Entity's Day-ahead Scheduling Reserves obligation that is met by bilateral arrangement(s).

(e) If the Day-ahead Scheduling Reserves Requirement is not satisfied through the operation of subsection (a) of this section, any additional Operating Reserves required to meet the requirement shall be scheduled by the Office of the Interconnection pursuant to Section 3.2.3 of Schedule 1 of this Agreement.

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 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 either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, 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 hourly in an amount equal to {(LMPDMW - AG) x (URTLMP - UB)}

where:

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 hourly integrated real time LMP;

AG equals the actual hourly integrated output of the unit;

URTLMP equals the real time LMP at the unit's bus;

UB equals the unit offer for that unit for which output is reduced or suspended determined according to the real time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UB shall not be negative.

(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 Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost 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 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.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG, or (ii) {(URTLMP – UB) x DAG where:

URTLMP equals the real time LMP at the unit's bus;

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

(e) At the end of each Operating Day, where the active energy 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).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is 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 hourly in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual hourly integrated output of the unit;

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 hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

UB equals the unit offer for that unit for which output is increased, determined according to the real time scheduled offer curve on which the unit was operating;

URTLMP equals the real time LMP at the unit's bus; and

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to 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~~A~~(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, 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 lost 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 lost 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 alternate lost 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 Tier 2 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 hourly Synchronized Reserve Market Clearing Price for each hour 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 generating unit's hourly cost to provide synchronous condensing, calculated in

accordance with the PJM Manuals, (B) the hourly product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generating unit's bus, (C) the generating unit's startup-cost of providing synchronous condensing, and (D) 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 paragraph (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 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. 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 (net of operating Behind The Meter Generation) 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 PJM 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 Tier 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 hourly Synchronized Reserve Market Clearing Price for each hour 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 generation resource's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) 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 section (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 (net of operating Behind The Meter Generation) 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 Section 5 of this Schedule.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Section 5 of this Schedule.

3.2.6 Emergency Energy.

(a) 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 hour of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange 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.

(b) 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 hour of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net PJM Interchange 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.

(c) The net costs or net revenues associated with sales or purchases of hourly energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each hour 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 PJM Interchange 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 Buyer in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market Buyer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Buyer's internal accounting.

(b) If deliveries to a Market Buyer that has PJM Interchange meters in accordance with Section 14 of the Operating Agreement include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market Buyer, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market Buyer and the unmetered Market Participant specified by them to the Office of the Interconnection.

3.3 Market Sellers.

Except as provided in the following sentence, the accounting and billing principles and procedures applicable to Generating Market Buyers functioning as Market Sellers shall be as set forth in Section 3.2. This Section sets forth the accounting and billing principles and procedures applicable to all other Market Sellers, and to Generating Market Buyers functioning as Market Sellers with respect to any matters not specified in Section 3.2.

3.3.1 Spot Market Energy Charges.

(a) Market Sellers shall be paid for all energy scheduled to be delivered in the Day-ahead Energy Market at the Day-ahead System Energy Prices.

(b) At the end of each hour during an Operating Day, the Office of the Interconnection shall determine the total net amount of energy delivered in the hour to the PJM Region by each of the Market Seller's resources, in accordance with the PJM Manuals and the calculation described in Section 3.2.1(f).

(c) The Office of the Interconnection shall calculate Day-ahead and Real-time System Energy Prices for the PJM Region, in accordance with Section 2 of this Schedule.

(d) A Market Seller shall be paid for real-time sales of Spot Market Energy to the extent of its hourly net deliveries to the PJM Region of energy in excess of amounts scheduled in the Day-ahead Energy Market from the Market Seller's resources. For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the hourly amounts delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region. The total real-time generation revenues for each Market Seller shall be the sum of its payments determined by the product of (i) the hourly net amount of energy delivered to the PJM Region in excess of the amount scheduled to be delivered in that hour ~~at that bus~~ in the Day-ahead Energy Market from each of the Market Seller's resources, times (ii) the hourly Real-time System Energy Price. To the extent that the energy actually injected in any hour is less than the energy scheduled to be injected ~~at that bus~~ in the Day-ahead Energy Market, the Market Seller shall be debited for the difference at the Real-time System Energy Price at the time of the shortfall times the amount of the shortfall. The total generation revenue for each Market Seller shall be the sum, of the revenues at Day-ahead System Energy Prices determined in accordance with the Day-ahead Energy Market as specified in Section 3.3.1(a) plus the revenues at Real-time System Energy Prices determined as specified herein, net of any debits specified herein for each Market Seller.

3.3.2 Regulation.

Each Market Seller that is also an Internal Market Buyer as to load in a Regulation Zone shall have an hourly Regulation objective and shall be credited or charged in connection therewith as specified in Section 3.2.2. All other Market Sellers supplying Regulation in such Regulation Zone at the direction of the Office of the Interconnection shall be credited for each increment of

such Regulation at the price specified in Section 3.2.2(b), as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

3.3.3 Operating Reserves.

A Market Seller shall be credited for its pool-scheduled resources based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource, in accordance with the procedures set forth in Section 3.2.3.

3.3.4 Emergency Energy.

The net costs or net revenues associated with purchases or sales of energy in connection with Emergencies in the PJM Region, or in another Control Area, shall be allocated to Market Participants in accordance with the procedures set forth in Section 3.2.6.

3.3.5 Synchronized Reserve.

Each Market Seller that is also an Internal Market Buyer shall have an hourly Synchronized Reserve objective and shall be credited or charged in connection therewith as specified in Section 3.2.3A(a). All other Market Sellers supplying Synchronized Reserve at the direction of the Office of the Interconnection shall be credited for each increment of such Synchronized Reserve at the price specified in Section 3.2.3A(b), as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

3.3.6 Billing.

PJMSettlement shall prepare a billing statement each billing cycle for each Market Seller in accordance with the charges and credits specified in Sections 3.3.1 through 3.3.5 of this Schedule, and showing the net amount to be paid or received by the Market Seller. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Seller's internal accounting.

5.1 Transmission Congestion Charge Calculation.

5.1.1 Calculation by Office of the Interconnection.

When the transmission system is operating under constrained conditions, or as necessary to provide third-party transmission provider losses ~~in accordance with Section 9.3~~, the Office of the Interconnection shall calculate Transmission Congestion Charges for each Network Service User, Market Participants in the PJM Interchange Energy Market, and each Transmission Customer.

5.1.2 General.

The Office of the Interconnection shall calculate Congestion Prices in the form of Day-ahead Congestion Prices and Real-time Congestion Prices for the PJM Region, in accordance with Section 2 of this Schedule.

5.1.3 Network Service User Calculation.

(a) Each Network Service User shall be charged for the increased cost of energy incurred by it during each constrained hour to deliver the output of its firm Generation Capacity Resources or other owned or contracted for resources, its firm bilateral purchases, and its non-firm bilateral purchases as to which it has elected to pay Transmission Congestion Charges. ~~The Transmission Congestion Charge for deliveries from each such source shall be the Network Service User's hourly congestion net bill.~~

(b) Market Buyers shall be charged for transmission congestion resulting from all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy market in the Day-ahead Energy Market at the Day-ahead Congestion prices applicable to each relevant load bus.

(c) Generating Market Buyers shall be reimbursed for transmission congestion resulting from all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant generation bus.

(d) Market Sellers shall be reimbursed for transmission congestion resulting from all energy scheduled to be delivered in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant generation bus.

(e) The hourly net amount of energy delivered at each generation bus is determined by revenue meter data if available, or by the State Estimator, if revenue meter data is not available. The total load actually served at each load bus is initially determined by the State Estimator. For each Electric Distributor that reports hourly net energy flows from metered tie lines and for which all generators within the Electric Distributor's territory report revenue quality, hourly net energy delivered, the total revenue meter load within the Electric Distributor's territory is calculated as the sum of all net import energy flows reported by their tie revenue

meters and all net generation reported via generator revenue meters. The amount of load at each of such Electric Distributor's load buses calculated by the State Estimator is then adjusted, in proportion to its share of the total load of that Electric Distributor, in order that the total amount of load across all of the Electric Distributor's load buses matches its total revenue meter calculated load.

(f) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the Transmission Congestion Charges at each Market Buyer's load bus to be charged for congestion at Real-time Congestion Prices determined by the product of the hourly Real-time Congestion Price at the relevant bus times the Market Buyer's megawatts of load (net of operating Behind The Meter Generation, but not to be less than zero) at the bus in that hour in excess of the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the hour in the Day-ahead Energy Market. To the extent that the load (net of operating Behind The Meter Generation, but not to be less than zero) actually served at a load bus is less than the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the Day-ahead Energy Market, the Market Buyer shall be paid for the difference at the Real-time Congestion Price for the load bus at the time of the shortfall. The megawatts of load at each load bus shall be the sum of the megawatts of load (net of operating Behind The Meter Generation, but not less than zero) for that bus of that Market Buyer plus any megawatts of that Market Buyer's bilateral sales attributable to that bus. The total load charge for each Market Buyer shall be the sum, for each of a Market Buyer's load buses, of the charges at Day-ahead Congestion Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1a plus the charges at Real-time Congestion Prices determined as specified herein, net of any payments specified herein for each of the Market Buyer's load buses.

(g) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the transmission congestion payments at each Generating Market Buyer's generation bus to be paid at Real-time Congestion Prices, determined by the product of the hourly Real-time Congestion Price at the relevant bus times the Generating Market Buyer's megawatts of generation at such generation bus in the hour in excess of the energy scheduled to be injected at that bus in that hour in the Day-ahead Energy Market. To the extent that the energy actually injected at the generation bus is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Generating Market Buyer shall be debited for the difference at the Real-time Congestion Price for the generation bus at the time of the shortfall. The megawatts of generation at each generation bus shall be the sum of the megawatts of generation for that bus of that Generating Market Buyer plus any megawatts of bilateral purchases of that Generating Market Buyer attributable to that bus. The total generation revenue for each Generating Market Buyer shall be the sum, for each of the Generating Market Buyer's generation buses, of the revenues at Day-ahead Congestion Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Congestion Prices determined as specified herein, net of any debits specified herein for each of the Market Buyer's generation buses.

(h) A Market Seller shall be paid for transmission congestion that results from the Real-time sales of energy to the extent of its hourly net deliveries to the PJM Region of energy in

excess of amounts scheduled in the Day-ahead Energy Market from the Market Seller's resources. For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the hourly amounts delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region. The total real-time generation revenues for each Market Seller shall be the sum of its credits determined by the product of (i) the hourly net amount of energy delivered to the PJM Region at the applicable generation or interface bus in excess of the amount scheduled to be delivered in that hour at that bus in the Day-ahead Energy Market from each of the Market Seller's resources, times (ii) the hourly Real-time Congestion Price at that bus. To the extent that the energy actually injected at a generation or interface bus in any hour is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Market Seller shall be debited for the difference at the Real-time Congestion Price for the applicable bus at the time of the shortfall times the amount of the shortfall. The total generation revenue for each Market Seller shall be the sum, for each of the Market Seller's generation buses or Interface Pricing Points, of the revenues at Day-ahead Congestion Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Congestion Prices determined as specified herein, net of any debits specified herein for each of the Market Seller's generation or interface buses.

5.1.4 Transmission Customer Calculation.

Each Transmission Customer using Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), each Network Customer, and each Transmission Customer using Non-Firm Point-to-Point Transmission Service (as defined in the PJM Tariff) that has elected to pay Transmission Congestion Charges, shall be charged for the increased cost of energy during constrained hours for the delivery of energy using such ~~Point-to-Point~~ Transmission Service. Except as specified in this subsection, a Transmission Congestion Charge shall be assessed for transmission use scheduled in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region and the Day-ahead Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. Transmission Congestion Charges shall be assessed for real-time transmission use in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. A Transmission Customer shall be paid for Transmission Congestion Charges for real-time transmission use falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. ~~Real-time deviations from the Point-to-Point Transmission Service scheduled in the Day-ahead Energy Market shall be determined by the lesser of the real-time injection or withdrawal associated with such transmission service.~~

5.1.4A Transaction Calculation.

Each Market Participant entering into transactions in the PJM Interchange Energy Markets shall be charged for the increased cost of energy during constrained hours for the delivery of energy on the scheduled path. Except as specified in this subsection, a Transmission Congestion Charge shall be assessed for cleared MWh in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Congestion Price at the sink point and the Day-ahead Congestion Price at the source point. Transmission Congestion Charges shall be assessed for real-time cleared MWh in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Congestion Price at the sink point and the Real-time Congestion Price at the source point. Such Market Participant shall be paid for Transmission Congestion Charges for real-time cleared MWh falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Congestion Price at the sink point and the Real-time Congestion Price at the source point.

5.1.5 Operating Margin Customer Calculation.

Each Control Area purchasing Operating Margin shall be assessed Transmission Congestion Charges for any increase in the cost of energy resulting from the provision of Operating Margin. The Transmission Congestion Charge shall be the amount of Operating Margin purchased in an hour multiplied by the difference in the Locational Marginal Price at what would be the delivery Interface Pricing Point and the Locational Marginal Price at what would be the source Interface Pricing Point, if the operating contingency that was the basis for the purchase of Operating Margin had occurred in that hour. Operating Margin may be allocated among multiple source and delivery Interface Pricing Points in accordance with an applicable load flow study.

5.1.6 Transmission Loading Relief Customer Calculation.

(a) Each Transmission Loading Relief Customer shall be assessed Transmission Congestion Charges for any increase in the cost of energy in the PJM Region resulting from its energy schedules over contract paths outside the PJM Region during Transmission Loading Relief.

(b) The Transmission Congestion Charge shall be the total amount of energy specified in such energy schedules multiplied by the difference between a Locational Marginal Price calculated by the Office of the Interconnection for the energy schedule source location specified in the NERC Interchange Distribution Calculator and a Locational Marginal Price calculated by the Office of the Interconnection for the energy schedule sink location specified in the NERC Interchange Distribution Calculator. Transmission Congestion Charges that are less than zero shall be set equal to zero for Transmission Loading Relief Customers.

(c) The Office of the Interconnection will determine the Locational Marginal Prices at the energy schedule source and sink locations external to PJM with reference to and based solely on the prices of energy in the PJM Region and at the Interface Pricing Points between adjacent Control Areas and the PJM Region and the system conditions and actual power flow

distributions as described by the PJM State Estimator program. The Office of the Interconnection will determine the Locational Marginal Prices at the external energy schedule source and sink locations and the resulting Congestion Charge based on the portion of the energy schedule that flows through the PJM Region as reflected by the flow distributions from the PJM State Estimator program.

5.1.7 Total Transmission Congestion Charges.

The total Transmission Congestion Charges collected by PJMSettlement each hour will be the aggregate net amounts determined as specified in ~~this Schedule~~ the PJM Manuals. PJMSettlement shall collect Transmission Congestion Charges for each hour the transmission system operates under constrained conditions.

5.4 Transmission Loss Charge Calculation.

5.4.1 Calculation by Office of the Interconnection.

The Office of the Interconnection shall calculate Transmission Loss Charges for each Network Service User, Market Participant in the PJM Interchange Energy Market, and each Transmission Customer.

5.4.2 General.

(a) The basis for the Transmission Loss Charges shall be the differences in the Locational Marginal Prices, defined as the Loss Price at a bus, between points of delivery and points of receipt, as determined in accordance with Section 2 of this Schedule. (b) The Office of the Interconnection shall calculate Loss Prices in the form of Day-ahead Loss Prices and Real-time Loss Prices for the PJM Region, in accordance with Section 2 of this Schedule.

5.4.3 Network Service User Calculation.

(a) Each Network Service User shall be charged for the increased cost of transmission losses to deliver the output of its firm Capacity Resources or other owned or contracted for resources, its firm bilateral purchases, and its non-firm bilateral purchases. ~~The Transmission Loss Charge for deliveries from each such source shall be the Network Service User's hourly losses net bill.~~

(b) Market Buyers shall be charged for transmission losses resulting from all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead Loss Price applicable to each relevant load bus.

(c) Generating Market Buyers shall be reimbursed for transmission losses resulting from all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead Loss Price applicable to each relevant generation bus.

(d) Market Sellers shall be reimbursed for transmission losses resulting from all energy scheduled to be delivered in the Day-ahead Energy Market at the Day-ahead Loss Prices applicable to each relevant generation bus.

(e) The hourly net amount of energy delivered at each generation bus is determined by revenue meter data, if available, or by the State Estimator, if revenue meter data is not available. The total load actually served at each load bus is initially determined by the State Estimator. For each Electric Distributor that reports hourly net energy flows from metered tie lines and for which all generators within the Electric Distributor's territory report revenue quality, hourly net energy delivered, the total revenue meter load within the Electric Distributor's territory is calculated as the sum of all net import energy flows reported by their tie revenue meters and all net generation reported via generator revenue meters. The amount of load at each of such Electric Distributor's load buses calculated by the State Estimator is then adjusted, in

proportion to its share of the total load of that Electric Distributor, in order that the total amount of load across all of the Electric Distributor's load buses matches its total revenue meter calculated load.

(f) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the Transmission Loss Charges at each Market Buyer's load bus to be charged for losses at Real-time Loss Prices determined by the product of the hourly Real-time Loss Prices at the relevant bus times the Market Buyer's megawatts of load (net of operating Behind The Meter Generation, but not to be less than zero) at the bus in that hour in excess of the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the hour in the Day-ahead Energy Market. To the extent that the load (net of operating Behind The Meter Generation, but not to be less than zero) actually served at a load bus is less than the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the Day-ahead Energy Market, the Market Buyer shall be paid for the difference at the Real-time Loss Price for the load bus at the time of the shortfall. The megawatts of load at each load bus shall be the sum of the megawatts of load (net of operating Behind The Meter Generation, but not less than zero) for that bus of that Market Buyer plus any megawatts of that Market Buyer's bilateral sales attributable to that bus. The total load charge for each Market Buyer shall be the sum, for each of a Market Buyer's load buses, of the charges at Day-ahead Loss Price determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1a plus the charges at Real-time Loss Prices determined as specified herein, net of any payments specified herein for each of the Market Buyer's load buses.

(g) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the transmission loss payments at each Generating Market Buyer's generation bus to be paid at Real-time Loss Prices, determined by the product of the hourly Real-time Loss Price at the relevant bus times the Generating Market Buyer's megawatts of generation at such generation bus in the hour in excess of the energy scheduled to be injected at that bus in that hour in the Day-ahead Energy Market. To the extent that the energy actually injected at the generation bus is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Generating Market Buyer shall be debited for the difference at the Real-time Loss Price for the generation bus at the time of the shortfall. The megawatts of generation at each generation bus shall be the sum of the megawatts of generation for that bus of that Generating Market Buyer plus any megawatts of bilateral purchases of that Generating Market Buyer attributable to that bus. The total generation revenue for each Generating Market Buyer shall be the sum, for each of the Generating Market Buyer's generation buses, of the revenues at Day-ahead Loss Price determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Loss Prices determined as specified herein, net of any debits specified herein for each of the Market Buyer's generation buses.

(h) A Market Seller shall be paid for transmission losses that results from the Real-time sales of Spot Market Energy to the extent of its hourly net deliveries to the PJM Region of energy in excess of amounts scheduled in the Day-ahead Energy Market from the Market Seller's resources. For pool External Resources, the Office of the Interconnection shall model,

based on an appropriate flow analysis, the hourly amounts delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region. The total real-time generation revenues for each Market Seller shall be the sum of its credits determined by the product of (i) the hourly net amount of energy delivered to the PJM Region at the applicable generation or interface bus in excess of the amount scheduled to be delivered in that hour at that bus in the Day-ahead Energy Market from each of the Market Seller's resources, times (ii) the hourly Real-time Loss Price at that bus. To the extent that the energy actually injected at a generation bus or Interface Pricing Point in any hour is less than the energy scheduled to be injected at that bus or point in the Day-ahead Energy Market, the Market Seller shall be debited for the difference at the Real-time Loss Price for the applicable bus or point at the time of the shortfall times the amount of the shortfall. The total generation revenue for each Market Seller shall be the sum, for each of the Market Seller's generation buses or Interface Pricing Points, of the revenues at Day-ahead Loss Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Loss Prices determined as specified herein, net of any debits specified herein for each of the Market Seller's generation buses or Interface Pricing Points.

5.4.4 Transmission Customer Calculation.

Each Transmission Customer using Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), each Network Customer, and each Transmission Customer using Non-Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), shall be charged for the increased cost of transmission losses for the delivery of energy using ~~Point-to-Point~~such Transmission Service. Except as specified in this subsection, a Transmission Loss Charge shall be assessed for transmission use scheduled in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Loss Price at the delivery point or the delivery interface at the boundary of the PJM Region and the Day-ahead Loss Price at the source point or the source interface at the boundary of the PJM Region. Transmission Loss Charges shall be assessed for real-time transmission use in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Loss Price at the delivery point or the delivery interface at the boundary of the PJM Region, and the Real-time Loss Price at the source point or the source interface at the boundary of the PJM Region. A Transmission Customer shall be paid for Transmission Loss Charges for real-time transmission use falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Loss Price at the delivery point or the delivery interface at the boundary of the PJM Region, and the Real-time Loss Price at the source point or the source interface at the boundary of the PJM Region or the source Interface Pricing Point at the boundary of the PJM Region. ~~Real-time deviations from the Point-to-Point Transmission Service scheduled in the Day-ahead Energy Market shall be determined by the lesser of the real-time injection or withdrawal associated with such transmission service.~~

5.4.4A Transaction Calculation.

Each Market Participant entering into transactions in the PJM Interchange Energy Market shall be charged for the increased cost of transmission losses on the scheduled path. Except as

specified in this subsection, a Transmission Loss Charge shall be assessed for cleared MWh in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Loss Price at the sink point and the Day-ahead Loss Price at the source point. Transmission Loss Charges shall be assessed for real-time cleared MWh in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Loss Price at the sink point and the real-time Loss Price at the source point. Such Market Participant shall be paid for Transmission Loss Charges for real-time cleared MWh falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Loss Price at the sink point and the Real-time Loss Price at the source point.

5.4.5 Total Transmission Loss Charges.

The total Transmission Loss Charges collected by PJMSettlement each hour will be the aggregate net amounts determined as specified in this Schedule.

ATTACHMENT M – APPENDIX

I. CONFIDENTIALITY OF DATA AND INFORMATION

A. Party Access:

1. 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 Market Monitoring Unit, to the extent such documents, data or information have been designated as confidential pursuant to the procedures adopted by 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.

2. Except as may be provided in this Appendix, the Plan, the PJM Operating Agreement or in the PJM Tariff, the Market Monitoring Unit 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 Market Monitoring Unit or by such Member or entity applying for membership; provided that nothing contained herein shall prohibit the Market Monitoring Unit 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. The Market Monitoring Unit shall collect and use confidential information only in connection with its authority under this Appendix, the Plan, the PJM Operating Agreement or in the PJM Tariff and the retention of such information shall be in accordance with PJM's data retention policies.

3. Nothing contained herein shall prevent the Market Monitoring Unit from releasing a Member's confidential data or information to a third party provided that the Member has delivered to 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 Market Monitoring Unit 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 Market Monitoring Unit, who shall cease such release as soon as practicable after receipt of such withdrawal notice.

4. Reciprocal provisions to this Section I hereof, delineating the confidentiality requirements of the Office of the Interconnection and PJM members, are set forth in Section 18.17 of the PJM Operating Agreement.

B. Required Disclosure:

1. Notwithstanding anything in the foregoing section to the contrary, and subject to the provisions of Section I.C below, if the Market Monitoring Unit is required by applicable law, 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 the PJM Tariff, PJM Operating Agreement, Attachment M or this Appendix, the Market Monitoring Unit may make disclosure of such information; provided, however, that as soon as the Market Monitoring Unit learns of the disclosure requirement and prior to making disclosure, the Market Monitoring Unit 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 Market Monitoring Unit shall cooperate with such affected Members to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. The Market Monitoring Unit 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.

2. Nothing in this Section I shall prohibit or otherwise limit the Market Monitoring Unit's use of information covered herein if such information was: (i) previously known to the Market Monitoring Unit without an obligation of confidentiality; (ii) independently developed by or for the Office of the Interconnection and/or the PJM Market Monitor using non-confidential information; (iii) acquired by the Office of the Interconnection and/or the PJM Market Monitor from a third party which is not, to the Office of the Market Monitoring Unit'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 I.

3. The Market Monitoring Unit shall impose on any contractors retained to provide technical support or otherwise to assist with the implementation of the Plan or this Appendix a contractual duty of confidentiality consistent with the Plan or this Appendix. 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 Market Monitoring Unit shall not provide any such information to any such contractor without the express written permission of the Member providing the information.

C. <u>Disclosure to FERC</u>:

1. Notwithstanding anything in this Section I to the contrary, if the FERC or its staff, during the course of an investigation or otherwise, requests information from the Market Monitoring Unit that is otherwise required to be maintained in confidence pursuant to the PJM Tariff, the PJM Operating Agreement, the Plan or this Appendix, the Market Monitoring Unit shall provide the requested information to the FERC or its staff, within the time provided for in the request for information. In providing the information to the FERC or its staff, the Market Monitoring Unit may, consistent with 18 C.F.R. § 388.112, request that the information be treated as confidential and non-public by the FERC and its staff and that the information be withheld from public disclosure. The Market Monitoring Unit shall notify any affected Member(s) when it is notified by FERC or its staff, that a request for disclosure of, or decision to disclose, confidential information has been received, at which time the Office of the Interconnection, the Market Monitoring Unit, and/or the affected Member may respond before such information would be made public, pursuant to 18 C.F.R. § 388.112.

2. The foregoing Section I.C.1 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, PJM and/or the Market Monitoring Unit shall follow the procedures in Section 18.17.2.

D. Disclosure to Authorized Commissions:

1. Notwithstanding anything in this Section I to the contrary, the Market Monitoring Unit shall disclose confidential information, otherwise required to be maintained in confidence pursuant to the PJM Tariff, the PJM Operating Agreement, the Plan or this Appendix, 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 to the PJM Operating Agreement as 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 FERC 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 protest proceeding. If there are material changes in law that affect the accuracy and adequacy of the representations in the Certification filed with the FERC, 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 FERC as set forth above in this paragraph.

(ii) Neither the Office of the Interconnection nor the Market Monitoring Unit may disclose data to an Authorized Commission during the FERC's consideration of the Certification and any filed protests. If the FERC 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 I. In the event that an interested party protests the Authorized Commission's Certification and the FERC 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.

(iii) Any confidential information provided to an Authorized Commission pursuant to this Section I shall not be further disclosed by the recipient Authorized Commission except by order of the FERC.

(iv) The Market Monitoring Unit 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.

(v) The Authorized Commission may provide confidential information obtained from the Market Monitoring Unit 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 nondisclosure agreement in the form attached to the PJM Operating Agreement as Schedule 10 before being provided access to any such confidential information.

2. The Market Monitoring Unit 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 Market Monitoring Unit will not make any written or electronic disclosures of confidential information to the Authorized Person pursuant to this Section I.D.2. In any such discussions, the Market Monitoring Unit 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 Market Monitoring Unit shall also be authorized to assist Authorized Persons in interpreting confidential information that is disclosed. The Market Monitoring Unit 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.

3. 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 Market Monitoring Unit, 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 Market Monitoring Unit 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 I.D.3(iii) below, the Market Monitoring Unit 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 Market Monitoring Unit 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 Market Monitoring Unit 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 Market Monitoring Unit shall not reveal any Member's confidential information to any other Member.

(iii) Notwithstanding Section I.D.3(ii), above, should the Office of the Interconnection, the Market Monitoring Unit or an Affected Member object to an Information Request or any portion thereof, any of them may, within four (4) business days following the Market Monitoring Unit'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, Market Monitoring Unit, or the Affected Member may file a complaint with the FERC 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 the 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 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 and/or Market Monitoring Unit 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 Market Monitoring Unit shall use its best efforts to respond to the Information Request promptly.

(iv) Any Authorized Commission may initiate appropriate legal action at the 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).

4. 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 Market Monitoring Unit, 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 I.

(ii) The Office Market Monitoring Unit shall terminate the right of such Authorized Commission to receive confidential information under this Section I 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 Market Monitoring Unit's actions under this Section I shall be to Commission. An Authorized Commission shall be entitled to reestablish its certification as set forth in Section I.D.1 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 recertification filing with sixty (60) days of the date of the filing, the recertification 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, the Market Monitoring Unit, and/or the Affected Member shall have the right to seek and obtain at least the following types of relief: (a) an order from the 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 Market Monitoring Unit.

(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 I.D.4(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 I.D.4(ii) or I.D.4(iii)(a) above, shall be submitted to the FERC for hearing and resolution. Any dispute or conflict requesting the relief in Section I.D.4(iii)(c) above may be submitted to FERC or any court of competent jurisdiction for hearing and resolution.

E. Market Monitoring:

1. Subject to the requirements of Section E.2, the Market Monitoring Unit may release confidential information of Public Service Electric & Gas Company ("PSE&G"), Consolidated Edison Company of New York ("ConEd"), and their affiliates, and the confidential information of any Member regarding generation and/or transmission facilities located within the PSE&G Zone to the New York Independent System Operator, Inc. ("New York ISO"), the market monitoring unit of New York ISO and the New York ISO Market Advisor to the limited extent that PJM or the Market Monitoring Unit determines necessary to carry out the responsibilities of PJM, New York ISO or the market monitoring units of PJM and the New York ISO under FERC Opinion No. 476 (see Consolidated Edison Company v. Public Service Electric and Gas Company, et al., 108 FERC ¶ 61,120, at P 215 (2004)) to conduct joint investigations to ensure that gaming, abuse of market power, or similar activities do not take place with regard to power transfers under the contracts that are the subject of FERC Opinion No. 476.

2. The Market Monitoring Unit may release a Member's confidential information pursuant to Section I.E.1 to the New York ISO, the market monitoring unit of the New York ISO and the New York ISO Market Advisor only if the New York ISO, the market monitoring unit of the New York ISO and the New York ISO Market Advisor are subject to obligations limiting the disclosure of such information that are equivalent to or greater than the limitations on disclosure specified in this Section I.E. Information received from the New York ISO, the market monitoring unit of the New York ISO, or the New York ISO Market Advisor under Section I.E.1 that is designated as confidential shall be protected from disclosure in accordance with this Section I.E.

II. DEVELOPMENT OF INPUTS FOR PROSPECTIVE MITIGATION

A. Offer Price Caps:

1. The Market Monitor or his designee shall advise the Office of the Interconnection whether it believes that the cost references, methods and rules included in the Cost Development Guidelines are accurate and appropriate, as specified in the PJM Manuals.

2. The Market Monitoring Unit shall review upon request of a Market Seller, and may review upon its own initiative at any time, the incremental costs (defined in Section 6.4.2 of Schedule 1of the Operating Agreement) included in the Offer Price Cap of a generating unit in order to ensure that the Market Seller has correctly applied the Cost Development Guidelines and that the level of the Offer Price Cap is otherwise acceptable.

3. The Market Monitoring Unit shall issue a written notice to a unit indicating that it is a "Frequently Mitigated Unit" or "FMU," or an "Associated Unit," when the Market Monitoring Unit determines that the unit meets the criteria delineated in Section 6.4.2 of Schedule 1 of the Operating Agreement.

4. Notwithstanding the number of jointly pivotal suppliers in any hour, if the Market Monitoring Unit determines that a reasonable level of competition will not exist based on an evaluation of all facts and circumstances, it may propose to the Commission the removal of offer-capping suspensions otherwise authorized by Section 6.4 of the Operating Agreement. Such proposals shall take effect upon Commission acceptance of the Market Monitoring Unit's filing.

B. <u>Minimum Generator Operating Parameters</u>:

1. The Market Monitoring Unit shall provide to the Office of the Interconnection a table of default unit class specific parameter limits to be known as the "Parameter Limited Schedule Matrix" to be included in Section 6.6(c) of Schedule 1 of the Operating Agreement. The Parameter Limited Schedule Matrix shall include default values on a unit-type basis as specified in Section 6.6(c). The Market Monitoring Unit shall review the Parameter Limited Schedule Matrix twice yearly, and, in the event it determines that revision is appropriate, shall provide a revised matrix to the Office of the Interconnection by no later than December 31 and June 30, respectively, prior to the bi-annual enrollment periods for the submission of start-up and no-load costs on April 1 and October 1.

2. The Market Monitoring Unit shall notify Generation Capacity Resources no later than March 15 and September 15 each year of its determination regarding each request for an exception to a value specified in the Parameter Limited Schedule Matrix or the parameters defined in Section 6.6 of Schedule 1 of the Operating Agreement and the PJM Manuals, provided that the Market Monitoring Unit receives such request by no later than February 28 or August 31, respectively. The Market Monitoring Unit's determination for an exception shall continue for a period of no less than six months, and, if requested, for such longer period as the Market Monitoring Unit may determine is supported by the data.

3. When a Generation Capacity Resource notifies the Market Monitoring Unit of a material change to the facts relied upon by the Market Monitoring Unit to support a parameter limited schedule exception pursuant to Section 6.7 of Schedule 1 of the Operating Agreement (or the Commission in support of its approval), the Market Monitoring Unit shall either agree to continue the existing exception, agree to a revised exception or find that no exception is supported by the data, in which case the values specified in the parameter limited schedule matrix shall apply.

4. The Market Monitoring Unit shall notify the Office of the Interconnection of any risk premium to which it and a nuclear generation resource agree or its determination if agreement is not obtained. If a nuclear generation resource submits a risk premium inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such risk premium, the Market Monitoring Unit may exercise its powers to inform Commission staff of its

concerns and request a determination that would require the nuclear generation resource to submit an appropriate risk premium.

C. RPM Must-Offer Obligation:

1. The Market Monitoring Unit shall maintain, post on its website and provide to the Office of the Interconnection prior to each RPM Auction (updated, as necessary, on at least a quarterly basis), a list of Existing Generation Capacity Resources located in the PJM Region that are subject to the "must-offer" obligation set forth in Section 6.6 of Attachment DD.

2. The Market Monitoring Unit shall evaluate requests submitted by Capacity Market Sellers for a determination that a Generation Capacity Resource, or any portion thereof, be removed from Capacity Resource status or exempted from status as a Generation Capacity Resource subject to Section II.C.1 above and inform both the Capacity Market Seller and the Office of the Interconnection of such determination. A Generation Capacity Resource located in the PJM Region shall not be removed from Capacity Resource status to the extent the resource is committed to service of PJM loads as a result of an RPM Auction, FRR Capacity Plan, Locational UCAP transaction and/or by designation as a replacement resource under this Attachment DD.

3. The Market Monitoring Unit shall evaluate the data and documentation provided to it by a potential Capacity Market Seller to establish the EFORd to be included in a Sell Offer applicable to each resource pursuant to Section 6.6 of Attachment DD, then it shall notify the Office of the Interconnection of any EFORd to which it and the Generation Capacity Resource agree or its determination of the EFORd if agreement is not obtained.

4. The Market Monitoring Unit shall consider the documentation provided to it by a potential Capacity Market Seller pursuant to Section 6.6 of Attachment DD, and determine whether a resource owned or controlled by such Capacity Market Seller meets the criteria to qualify for an exception to the must-offer requirement because the resource (i) is reasonably expected to be physically unable to participate in the relevant auction; (ii) has a financially and physically firm commitment to an external sale of its capacity; or (iii) was interconnected to the Transmission System as an Energy Resource and not subsequently converted to a Capacity Resource. The Market Monitoring Unit shall inform both the Capacity Market Seller and the Office of the Interconnection of its determination within ten (10) business days of its initial receipt of the documentation.

In order to establish that a resource is reasonably expected to be physically unable to participate in the relevant auction as set forth in (i) above, the Capacity Market Seller must demonstrate that:

A. It has a documented plan in place to retire the resource prior to or during the Delivery Year, and has submitted a notice of Deactivation to the Office of the Interconnection consistent with Section 113.1 of the PJM Tariff, without regard to whether the Office of the Interconnection has requested the Capacity Market Seller to continue to operate the resource beyond its desired deactivation date in accordance with Section 113.2 of the PJM Tariff for the

purpose of maintaining the reliability of the PJM Transmission System and the Capacity Market Seller has agreed to do so;

B. Significant physical operational restrictions cause long term or permanent changes to the installed capacity value of the resource, or the resource is under major repair that will extend into the applicable Delivery Year, that will result in the imposition of RPM performance penalties pursuant to Attachment DD of the PJM Tariff;

C. The Capacity Market Seller is involved in an ongoing regulatory proceeding (e.g. – regarding potential environmental restrictions) specific to the resource and has received an order, decision, final rule, opinion or other final directive from the regulatory authority that will result in the retirement of the resource; or,

D. A resource considered an Existing Generating Capacity Resource because it cleared an RPM Auction for a Delivery Year prior to the Delivery Year of the relevant auction, but which is not yet in service, is unable to achieve full commercial operation prior to the Delivery Year of the relevant auction. The Capacity Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer certifying that the resource will not be in full commercial operation prior to the referenced Delivery Year.

5. If a Capacity Market Seller submits for the portion of a Generation Capacity Resource that it owns or controls, and the Office of Interconnection accepts, a Sell Offer (i) at a level of installed capacity that the Market Monitoring Unit believes is inconsistent with the level established under Section 5.6.6 of Attachment DD of the PJM Tariff, (ii) at a level of installed capacity inconsistent with its determination of eligibility for an exception listed in Section II.C.4 above, or (iii) a maximum EFORd that the Market Monitoring Unit believes is inconsistent with the maximum level determined under Section II.C.3 of this Appendix, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and/or request a determination from the Commission that would require the Generation Capacity Resource to submit a new or revised Sell Offer, notwithstanding any determination to the contrary made under Section 6.6 of Attachment DD.

The Market Monitoring Unit shall also consider the documentation provided by the Capacity Market Seller pursuant to Section 6.6 of Attachment DD, for generation resources for which the Office of the Interconnection has not approved an exception to the must-offer requirement as set forth in Section 6.6(g) of Attachment DD, to determine whether the Capacity Market Seller's failure to offer part or all of one or more generation resources into an RPM Auction would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction as required by Section 6.6(i) of Attachment DD, and shall inform both the Capacity Market Seller and the Office of the Interconnection of its determination within ten (10) business days of its initial receipt of the documentation.

D. <u>Preliminary Market Structure Screen</u>:

1. In sufficient time to permit the posting required by Section 6.2(a) of Attachment DD, the Market Monitoring Unit shall apply the Preliminary Market Structure Screen to identify the

LDAs in which Capacity Market Sellers must provide the data specified in Section 6.7(b) of Attachment DD for any auction conducted with respect to such Delivery Year and whether Capacity Market Sellers must provide this data for the entire PJM Region. For each LDA and for the PJM Region, the Preliminary Market Structure Screen will be based on: (1) the Unforced Capacity available for such Delivery Year from Generation Capacity Resources located in such area; and (2) the Locational Deliverability Area Reliability Requirement and the PJM Reliability Requirement. For purposes of this screen, any LDA for which a separate Variable Resource Requirement Curve has not been established under Section 5.10 of Attachment DD shall be combined with all other such LDAs that form an electrically contiguous area ("Unconstrained LDA Group"), and the screen shall be applied to such area in the aggregate, rather than to each such LDA individually. Any such Unconstrained LDA Groups shall be identified in the posting required by Section 6.2(a) of Attachment DD.

2. An LDA, Unconstrained LDA Group, or the entire PJM Region shall fail the Preliminary Market Structure Screen, and Capacity Market Sellers owning or controlling any Generation Capacity Resource located in such LDA, Unconstrained LDA Group, or region shall be required to provide the information specified in Section 6.7 of Attachment DD, if any one of the following three conditions is met: (1) the market share of any Capacity Market Seller exceeds twenty percent; (2) the HHI for all such sellers is 1800 or higher; or (3) there are not more than three jointly pivotal suppliers.

3. By no later than 90 days prior to the conduct of the Base Residual Auction and each Incremental Auction for such Delivery Year, the Market Monitoring Unit shall provide to the Office of Interconnection and post or continue posting on its website for each LDA, Unconstrained LDA Group (if applicable) and to the entire PJM Region, the result of its Preliminary Market Structure Screen.

4. The Market Monitoring Unit shall not reflect in the Preliminary Market Structure Screen a firm external sale of capacity if a Capacity Market Seller has not met the requirements set forth in Section II.C.4(ii) above and Section 6.6 prior to the deadline for Capacity Market Sellers to submit data for such Preliminary Market Structure Screen, nor shall it reflect the removal of a resource (or portion thereof) from the Capacity Resource status list unless the associated unit-specific bilateral transaction is approved pursuant to subsection 5.6.6(c) or the designation of such resource (or portion thereof) as a network resource for the external load is demonstrated to the Office of the Interconnection.

5. The Preliminary Market Structure Screen shall reflect the removal of resources from PJM Capacity Resource status approved as provided under Section II.C.2 above no less than 30 days prior to the posting deadline.

E. <u>Market Seller Offer Caps</u>:

1. Based on the data and calculations submitted by the Capacity Market Sellers for each Existing Generation Capacity Resource and the formulas specified in Section 6.7(d) of Attachment DD, the Market Monitoring Unit shall calculate the Market Seller Offer Cap for each such resource, and notify the Capacity Market Seller one month prior to the auction of its determination. This provision is duplicated in Section 6.7(d) of Attachment DD.

2. The Market Monitoring Unit must attempt to reach agreement with the Capacity Market Seller on the level of the Market Seller Offer Cap. If such agreement cannot be reached because a Capacity Market Seller fails to submit data adequate to support the Market Seller Offer Cap requested, then the Market Monitoring Unit shall so inform the Office of the Interconnection. In the event that a Capacity Market Seller and the Market Monitoring Unit cannot come to agreement on the level of a Market Seller Offer Cap, then the Market Monitoring Unit shall inform the Capacity Market Seller and the Office of the Interconnection of its determination, and the Market Monitoring Unit may pursue any action available to it under Attachment M.

3. Nothing herein shall preclude any Capacity Market Seller and the Market Monitoring Unit from agreeing to, nor require either such entity to agree to, an alternative market seller offer cap determined on a mutually agreeable basis. Any such alternative offer cap shall be filed with the Commission for its approval. This provision is duplicated in Section 6.4(a) of Attachment DD.

F. Mitigation of Offers from Planned Generation Capacity Resources:

Pursuant to Section 6.5 of Attachment DD, the Market Monitoring Unit shall notify each Capacity Market Seller whose Sell Offer ~~that its Sell Offer~~ has been determined to be excessive.

G. Data Submission:

Pursuant to Section 6.7 of Attachment DD, the Market Monitoring Unit may request additional information from any potential auction participant as deemed necessary by the Market Monitoring Unit, including, without limitation, additional cost data on resources in a class that is not otherwise expected to include the marginal price setting resource; and compliance with such request shall be a condition of participation in any auction. All data submitted to the Office of the Interconnection or the Market Monitoring Unit by a Market Participant is subject to verification by the Market Monitoring Unit.

H. Determination of Avoidable Cost Rates:

1. The Market Monitoring Unit shall annually review the table of default Avoidable Cost Rates included in Section 6.7(c) of Attachment DD and calculated on the bases set forth therein, and determine whether the values included therein need to be updated. If so, the Market Monitoring Unit shall provide to the Office of the Interconnection updated values or notice of its determination that updated values are not needed.

2. The Market Monitoring Unit shall indicate in its posted reports on RPM performance the number of Generation Capacity Resources and megawatts per LDA that use the retirement Avoidable Cost Rates.

3. If a Capacity Market Seller does not elect to use a default Avoidable Cost Rate and has timely provided to the Market Monitoring Unit the data described in Section 6.7 of Attachment DD, the Market Monitoring Unit shall calculate the Avoidable Cost Rate (or may calculate, in

the case of the tardy receipt of data) and provide a unit-specific value to the Capacity Market Seller.

4. If a Capacity Market Sellers submits a retirement Avoidable Cost Rate that is higher than the applicable default Avoidable Cost Rate included in the table in Section 6.7 of Attachment DD, and the Capacity Market Seller and the Market Monitoring Unit do not agree that the proposed retirement Avoidable Cost Rate that has been submitted is appropriate, and the Office of the Interconnection accepts the proposed retirement Avoidable Cost Rate submitted by the Capacity Market Seller, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and request a determination that would require the Capacity Market Seller to utilize the retirement Avoidable Cost Rate determined by the Market Monitoring Unit or such other retirement Avoidable Cost Rate as determined by the Commission.

I. Determination of PJM Market Revenues:

The Market Monitoring Unit shall calculate the Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied pursuant to Section 6.8(d) of Attachment DD.

J. Determination of Opportunity Costs:

The Market Monitoring Unit shall review and verify the documentation of prices available to Existing Generation Capacity Resources in markets external to PJM and proposed for inclusion in Opportunity Costs pursuant to Section 6.7(d)(ii) of Attachment DD. The Market Monitoring Unit shall notify such Generation Capacity Resource and the Office of the Interconnection if it is dissatisfied with the documentation provided and whether it objects to the inclusion of such Opportunity Costs in a Market Seller Offer. If such Generation Capacity Resource submits a Market Seller Offer that includes Opportunity Costs that have not been documented and verified to the Market Monitoring Unit's satisfaction, then the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and request a determination that would require the Generation Capacity Resource to remove them.

III. BLACKSTART SERVICE

A. Upon the submission by a Black Start Service generator owner of a request for changes to the Black Start Service revenue requirements for the generator, the Black Start Service generator owner and the Market Monitoring Unit shall attempt to agree to values.

B. Pursuant to the terms of Schedule 6A of the PJM Tariff and the PJM Manuals, the Market Monitoring Unit will analyze any requested generator black start cost changes on an annual basis and shall notify the Office of the Interconnection of any costs to which it and the Black Start Service generator owner have agreed or the Market Monitoring Unit's determination regarding any cost components to which agreement has not been obtained. If a Black Start Service generator owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost component, and the Office of the Interconnection accepts the Black Start Service revenue requirements submitted by the Black

Start Service generator owner, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and request a determination that would require the Black Start Service generator to utilize the values determined by the Market Monitoring Unit or such other values as determined by the Commission.

IV. DEACTIVATION RATES

1. Upon receipt of a notice to deactivate a generating unit under Part V of the PJM Tariff from the Office of the Interconnection forwarded pursuant to Section 113.1 of the PJM Tariff, the Market Monitoring Unit shall analyze the effects of the proposed deactivation with regard to potential market power issues and shall notify the Office of the Interconnection and the generator owner (of, if applicable, its designated agent) within 30 days of the deactivation request if a market power issue has been identified. Such notice shall include the specific market power impact resulting from the proposed deactivation of the generating unit, as well as an initial assessment of any steps that could be taken to mitigate the market power impact.

2. The Market Monitoring Unit and the generating unit owner shall attempt to come to agreement on the level of each component included in the Deactivation Avoidable Cost Credit. In the case of cost of service filing submitted to the Commission in alternative to the Deactivation Cost Credit, the Market Monitoring Unit shall indicate to the generating unit owner in advance of filing its views regarding the proposed method or cost components of recovery. The Market Monitoring Unit shall notify the Office of the Interconnection of any costs to which it and the generating unit owner have agreed or the Market Monitoring Unit's determination regarding any cost components to which agreement has not been obtained. If a generating unit owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost components, the Market Monitoring Unit may exercise is powers to inform Commission staff of its concerns and seek a determination that would require the Generating unit to include an appropriate cost component. This provision is duplicated in Sections 114 and 119 of Part V of the PJM Tariff.

V. OPPORTUNITY COST CALCULATION

The Market Monitoring Unit shall review requests for opportunity cost compensation under Sections 3.2.3(f-3) and 3.2.3B(h) of Schedule 1 of the Operating Agreement, discuss with the Office of the Interconnection and individual Market Sellers the amount of compensation, and file exercise its powers to inform Commission staff of its concerns and request a determination of compensation as provided by such sections. These requirements are duplicated in Sections 3.2.3(f-3) and 3.2.3B(h) of Schedule 1 of the Operating Agreement.

VI. FTR FORFEITURE RULE

The Market Monitoring Unit shall calculate Transmission Congestion Credits as required under Section 5.2.1(b) of Schedule 1 of the Operating Agreement, including the determination of the identity of the holder of FTRs and an evaluation of the overall benefits accrued by an entity or affiliated entities trading in FTRs and virtual trading in the Day-ahead Energy Market, and provide such calculations to the Office of the Interconnection. Nothing in this section shall preclude the Market Monitoring Unit from action to recover inappropriate benefits from the

subject activity if the amount forfeited is less than the benefit derived by the FTR holder. If the Office of the Interconnection imposes a forfeiture of the Transmission Congestion Credit in an amount that the Market Monitoring Unit disagrees with, then it may exercise its powers to inform Commission staff of its concerns and request an adjustment.

VII. FORCED OUTAGE RULE

1. The Market Monitoring Unit shall observe offers submitted in the Day-ahead Energy Market to determine whether all or part of a generating unit's capacity (MW) is designated as Maximum Emergency and (i) such offer in the Real-time Energy Market designates a smaller amount of capacity from that unit as Maximum Emergency for the same time period, and (ii) there is no physical reason to designate a larger amount of capacity as Maximum Emergency in the offer in the Day-ahead Energy Market than in the Real-time Energy Market, the Market Monitoring Unit shall notify the Office of Interconnection.

2. If the Market Monitoring Unit observes that (i) an offer submitted in the Day-ahead Energy market designates all or part of capacity (MW) of a Generating unit as economic maximum that is less than the economic maximum designated in the offer in the Real-time Energy Market, and (ii) there is no physical reason to designate a lower economic maximum in the offer in the Day-ahead Energy Market than in the offer in the Real-time Energy Market, the Market Monitoring Unit shall notify the Office of Interconnection.

VIII. DATA COLLECTION AND VERIFICATION

The Market Monitoring Unit shall gather and keep confidential detailed data on the procurement and usage of fuel to produce electric power transmitted in the PJM Region in order to assist the performance of its duties under Attachment M. To achieve this objective, the Market Monitoring Unit shall maintain on its website a mechanism that allows Members to conveniently and confidentially submit such data and develop a manual in consultation with stakeholders that describes the nature of and procedure for collecting data. Members of PJM owning a Generating unit that is located in the PJM Region (including dynamically scheduled units), or is included in a PJM Black Start Service plan, committed as a Generation Capacity Resource for the current or future Delivery Year, or otherwise subject to a commitment to provide service to PJM, shall provide data to the Market Monitoring Unit ~~in the manner prescribed in the PJM Manuals~~.

2. DEFINITIONS

Definitions specific to this Attachment are set forth below. In addition, any capitalized terms used in this Attachment not defined herein shall have the meaning given to such terms elsewhere in this Tariff or in the RAA. References to section numbers in this Attachment DD refer to sections of this attachment, unless otherwise specified.

2.1A Annual Demand Resource

"Annual Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.1B Annual Resource

"Annual Resource" shall mean a Generation Capacity Resource, an Energy Efficiency Resource or an Annual Demand Resource.

2.1C Annual Resource Price Adder

"Annual Resource Price Adder" shall mean an addition to the marginal value of Unforced Capacity and the Extended Summer Resource Price Adder as necessary to reflect the price of Annual Resources required to meet the applicable Minimum Annual Resource Requirement.

2.1D Annual Revenue Rate

"Annual Revenue Rate" shall mean the rate employed to assess a compliance penalty charge on a Demand Resource Provider or ILR Provider under section 11.

2.2 Avoidable Cost Rate

"Avoidable Cost Rate" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.3 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.

2.4 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~~ 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.

2.5 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.

2.6 Buy Bid

"Buy Bid" shall mean a bid to buy Capacity Resources in any Incremental Auction.

2.7 Capacity Credit

"Capacity Credit" shall have the meaning specified in Schedule 11 of the Operating Agreement, including Capacity Credits obtained prior to the termination of such Schedule applicable to periods after the termination of such Schedule.

2.8 Capacity Emergency Transfer Limit

"Capacity Emergency Transfer Limit" or "CETL" shall have the meaning provided in the Reliability Assurance Agreement.

2.9 Capacity Emergency Transfer Objective

"Capacity Emergency Transfer Objective" or "CETO" shall have the meaning provided in the Reliability Assurance Agreement.

2.9A Capacity Export Transmission Customer

"Capacity Export Transmission Customer" shall mean a customer taking point to point transmission service under Part II of this Tariff to export capacity from a generation resource located in the PJM Region that ~~is delisted from Capacity Resource status~~ has qualified for an exception to the RPM must-offer requirement as described in section 6.6(g)~~5.6.6(d)~~.

2.10 Capacity Market Buyer

"Capacity Market Buyer" shall mean a Member that submits bids to buy Capacity Resources in any Incremental Auction.

2.11 Capacity Market Seller

"Capacity Market Seller" shall mean a Member that owns, or has the contractual authority to control the output or load reduction capability of, a Capacity Resource, that has not transferred such authority to another entity, and that offers such resource in the Base Residual Auction or an Incremental Auction.

2.12 Capacity Resource

"Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.13 Capacity Resource Clearing Price

"Capacity Resource Clearing Price" shall mean the price calculated for a Capacity Resource that offered and cleared in a Base Residual Auction or Incremental Auction, in accordance with Section 5.

2.14 Capacity Transfer Right

"Capacity Transfer Right" shall mean a right, allocated to LSEs serving load in a Locational Deliverability Area, to receive payments, based on the transmission import capability into such Locational Deliverability Area, that offset, in whole or in part, the charges attributable to the Locational Price Adder, if any, included in the Zonal Capacity Price calculated for a Locational Delivery Area.

2.14A Conditional Incremental Auction

"Conditional Incremental Auction" shall mean an Incremental Auction conducted for a Delivery Year if and when necessary to secure commitments of additional capacity to address reliability criteria violations arising from the delay in a Backbone Transmission upgrade that was modeled in the Base Residual Auction for such Delivery Year.

2.15 CONE Area

"CONE Area" shall mean the areas listed in section 5.10(a)(iv)(A) and any LDAs established as CONE Areas pursuant to section 5.10(a)(iv)(B).

2.16 Cost of New Entry

"Cost of New Entry" or "CONE" shall mean the nominal levelized cost of a Reference Resource, as determined in accordance with section 5.

2.16A Credit-Limited Offer

"Credit-Limited Offer" shall have the meaning provided in Attachment Q to this Tariff.

2.17 Daily Deficiency Rate

"Daily Deficiency Rate" shall mean the rate employed to assess certain deficiency charges under sections 7, 8, 9, or 13.

2.18 Daily Unforced Capacity Obligation

"Daily Unforced Capacity Obligation" shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with Schedule 8 of the Reliability Assurance Agreement.

2.19 Delivery Year

Delivery Year shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Section 5.

2.20 Demand Resource

"Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.21 Demand Resource Factor

"Demand Resource Factor" shall have the meaning specified in the Reliability Assurance Agreement.

2.22 Demand Resource Provider

"Demand Resource Provider" shall mean a PJM Member that has the capability to reduce load, or that aggregates customers capable of reducing load. The Demand Resource Provider shall notify the Office of the Interconnection whether such load reduction is provided by a Limited Demand Resource, Extended Summer Demand Resource or an Annual Demand Resource. A Curtailment Service Provider, as defined in the Operating Agreement, may be a Demand Resource Provider, provided it qualifies its load reduction capability as a Limited Demand Resource, Extended Summer Demand Resource, or Annual Demand Resource.

2.23 EFORd

"EFORd" shall have the meaning specified in the PJM Reliability Assurance Agreement.

2.24 Energy Efficiency Resource

"Energy Efficiency Resource" shall have the meaning specified in the PJM Reliability Assurance Agreement.

2.24A Extended Summer Demand Resource

"Extended Summer Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.24B Extended Summer Resource Price Adder

"Extended Summer Resource Price Adder" shall mean an addition to the marginal value of Unforced Capacity as necessary to reflect the price of Annual Resources and Extended Summer Demand Resources required to meet the applicable Minimum Extended Summer Resource Requirement.

2.24C Extended Summer Demand Resource Reliability Target

"Extended Summer Demand Resource Reliability Target" for the PJM Region or an LDA, shall mean the maximum amount of the combination of Extended Summer Demand Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity, that shall be used to calculate the Minimum Annual Resource Requirement. As more fully set forth in the PJM Manuals, PJM calculates the Extended Summer DR Reliability Target, by first determining a reference annual loss of load expectation ("LOLE") assuming no Demand Resources. The calculation for the unconstrained portion of the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Capacity Emergency Transfer Objective study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of DR (displacing otherwise committed generation) as interruptible from May 1 through October 31 and unavailable from November 1 through April 30 and calculates the LOLE at each DR level. The Extended Summer DR Reliability Target is the DR amount, stated as a percentage of the unrestricted peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Extended Summer Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.25 [Reserved]

2.26 Final RTO Unforced Capacity Obligation

"Final RTO Unforced Capacity Obligation" shall mean the capacity obligation for the PJM Region, determined in accordance with Schedule 8 of the Reliability Assurance Agreement.

2.26A Final Zonal ILR Price

"Final Zonal ILR Price" shall mean the Adjusted Zonal Capacity Price after the Second Incremental Auction, less the amount paid in CTR credits per MW of load in the Zone in which the ILR is to be certified.

2.27 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.

2.28 Forecast Pool Requirement

"Forecast Pool Requirement" shall have the meaning specified in the Reliability Assurance Agreement.

2.29 Forecast RTO ILR Obligation

"Forecast RTO ILR Obligation" shall mean, in unforced capacity terms, the ILR Forecast for the PJM Region times the DR Factor, times the Forecast Pool Requirement, less the Unforced Capacity of all Demand Resources committed in FRR Capacity Plans by all FRR Entities in the PJM Region, for use in Delivery Years through May 31, 2012.

2.30 Forecast Zonal ILR Obligation

"Forecast Zonal ILR Obligation" shall mean, in unforced capacity terms, the ILR Forecast for the Zone times the DR Factor, times the Forecast Pool Requirement, less the Unforced Capacity of all Demand Resources committed in FRR Capacity Plans by all FRR Entities in such Zone, for use in Delivery Years through May 31, 2012.

2.31 Generation Capacity Resource

"Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.32 ILR Forecast

"ILR Forecast" shall mean, for any Delivery Year ending on or before May 31, 2012, the average annual megawatt quantity of ILR certified for the five Planning Periods preceding the date of the forecast; provided, however, that before such data becomes available for five Delivery Years under the Reliability Pricing Model, comparable data on Active Load Management (as defined in the preexisting reliability assurance agreements) from up to five prior Planning Periods shall be substituted as necessary; and provided further that, for transmission zones that were integrated into the PJM Region less than five years prior to the conduct of the Base Residual Auction for the Delivery Year, data on incremental load subject to mandatory interruption by Electric Distribution Companies within such zones shall be substituted as necessary.

2.33 ILR Provider

"ILR Provider" shall mean a Member that has the capability to reduce load, or that aggregates customers capable of reducing load. A Curtailment Service Provider, as such term is defined in the PJM Operating Agreement, may be an ILR Provider, provided it obtains certification of its load reduction capability as ILR.

2.34 Incremental Auction

"Incremental Auction" shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction), shall be held for the purposes of:

(i) allowing Market Sellers that committed Capacity Resources in the Base Residual Auction for a Delivery Year, which subsequently are determined to be unavailable to deliver the committed Unforced Capacity in such Delivery Year (due to resource retirement, resource cancellation or construction delay, resource derating, EFORD increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences) to submit Buy Bids for replacement Capacity Resources; and

(ii) allowing the Office of the Interconnection to reduce or increase the amount of committed capacity secured in prior auctions for such Delivery Year if, as a result of changed circumstances or expectations since the prior auction(s), there is, respectively, a significant excess or significant deficit of committed capacity for such Delivery Year, for the PJM Region or for an LDA.

2.35 Incremental Capacity Transfer Right

"Incremental Capacity Transfer Right" shall mean a Capacity Transfer Right allocated to a Generation Interconnection Customer or Transmission Interconnection Customer obligated to fund a transmission facility or upgrade, to the extent such upgrade or facility increases the transmission import capability into a Locational Deliverability Area, or a Capacity Transfer Right allocated to a Responsible Customer in accordance with Schedule 12A of the Tariff.

2.36 Interruptible Load for Reliability (ILR)

"Interruptible Load for Reliability" or "ILR" shall have the meaning specified in the Reliability Assurance Agreement.

2.36A Limited Demand Resource

"Limited Demand Resource**"** shall have the meaning specified in the Reliability Assurance Agreement.

2.36B Limited Demand Resource Reliability Target

"Limited Demand Resource Reliability Target**"** for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for the PJM Region or such LDA.

As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) more than ten times over those peak days; and ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result. Second, PJM adopts the lower result from these two tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.37 Load Serving Entity (LSE)

"Load Serving Entity" or "LSE" shall have the meaning specified in the Reliability Assurance Agreement.

2.38 Locational Deliverability Area (LDA)

"Locational Deliverability Area" or "LDA" shall mean a geographic area within the PJM Region that has limited transmission capability to import capacity to satisfy such area's reliability requirement, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, and as specified in Schedule 10.1 of the Reliability Assurance Agreement.

2.39 Locational Deliverability Area Reliability Requirement

"Locational Deliverability Area Reliability Requirement" shall mean the projected internal capacity in the Locational Deliverability Area plus the Capacity Emergency Transfer Objective for the Delivery Year, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, less the minimum internal resources required for all FRR Entities in such Locational Deliverability Area.

2.40 Locational Price Adder

"Locational Price Adder" shall mean an addition to the marginal value of Unforced Capacity within an LDA as necessary to reflect the price of Capacity Resources required to relieve applicable binding locational constraints.

2.41 Locational Reliability Charge

"Locational Reliability Charge" shall have the meaning specified in the Reliability Assurance Agreement.

2.41A Locational UCAP

"Locational UCAP" shall mean unforced capacity that a Member with available uncommitted capacity sells in a bilateral transaction to a Member that previously committed capacity through an RPM Auction but now requires replacement capacity to fulfill its RPM Auction commitment. The Locational UCAP Seller retains responsibility for performance of the resource providing such replacement capacity.

2.41B Locational UCAP Seller

"Locational UCAP Seller" shall mean a Member that sells Locational UCAP.

2.41C Market Seller Offer Cap

"Market Seller Offer Cap" shall mean a maximum offer price applicable to certain Market Sellers under certain conditions, as determined in accordance with section 6 of Attachment DD and section II.E of Attachment M - Appendix.

2.41D Minimum Annual Resource Requirement

"Minimum Annual Resource Requirement" shall mean the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Annual Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Extended Summer Demand Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Extended Summer Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

2.41E Minimum Extended Summer Resource Requirement

"Minimum Extended Summer Resource Requirement" shall mean the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a

separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

2.42 Net Cost of New Entry

"Net Cost of New Entry" shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset, as defined in Section 5.

2.43 Nominated Demand Resource Value

"Nominated Demand Resource Value" shall mean the amount of load reduction that a Demand Resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For existing Demand Resources, the maximum Nominated Demand Resource Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the Base Residual Auction or Incremental Auction is being conducted.

2.43A Nominated Energy Efficiency Value

"Nominated Energy Efficiency Value" shall mean the amount of load reduction that an Energy Efficiency Resource commits to provide through installation of more efficient devices or equipment or implementation of more efficient processes or systems.

2.44 Nominated ILR Value

"Nominated ILR Value" shall mean the amount of load reduction that an ILR resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For ILR, the maximum Nominated ILR Capacity Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the ILR is certified.

2.45 Opportunity Cost

"Opportunity Cost" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.46 Peak-Hour Dispatch

"Peak-Hour Dispatch" shall mean, for purposes of calculating the Energy and Ancillary Services Revenue Offset under section 5 of this Attachment, an assumption, as more fully set forth in the PJM Manuals, that the Reference Resource is *committed in the Day-Ahead Energy Market* in

four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average *day-ahead* LMP for the area for which the Net Cost of New Entry is being determined is greater than, or equal to, the cost to generate (including the cost for a complete start and shutdown cycle) for at least two hours during each four-hour block, where such blocks shall be assumed to be *committed* independently; provided that, if there are not at least two economic hours in any given four-hour block, then the Reference Resource shall be assumed not to be *committed* for such block*; and to the extent not committed in any such block in the Day-Ahead Energy Market under the above conditions based on Day-Ahead LMPs, is dispatched in the Real-Time Energy Market for such block if the Real-Time LMP is greater than or equal to the cost to generate under the same conditions as described above for the Day-Ahead Energy Market.* .

2.47 Peak Season

"Peak Season" shall mean the weeks containing the 24th through 36th Wednesdays of the calendar year. Each such week shall begin on a Monday and end on the following Sunday, except for the week containing the 36th Wednesday, which shall end on the following Friday.

2.48 Percentage Internal Resources Required

"Percentage Internal Resources Required" shall have the meaning specified in the Reliability Assurance Agreement.

2.49 Planned Demand Resource

"Planned Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.50 Planned External Generation Capacity Resource

"Planned External Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.50A Planned Generation Capacity Resource

"Planned Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.51 Planning Period

"Planning Period" shall have the meaning specified in the Reliability Assurance Agreement.

2.52 PJM Region

"PJM Region" shall have the meaning specified in the Reliability Assurance Agreement.

2.53 PJM Region Installed Reserve Margin

"PJM Region Installed Reserve Margin" shall have the meaning specified in the Reliability Assurance Agreement.

2.54 PJM Region Peak Load Forecast

"PJM Region Peak Load Forecast" shall mean the peak load forecast used by the Office of the Interconnection in determining the PJM Region Reliability Requirement, and shall be determined on both a preliminary and final basis as set forth in section 5.

2.55 PJM Region Reliability Requirement

"PJM Region Reliability Requirement" shall mean, for purposes of the Base Residual Auction, the Forecast Pool Requirement multiplied by the Preliminary PJM Region Peak Load Forecast, less the sum of all Preliminary Unforced Capacity Obligations of FRR Entities in the PJM Region; and, for purposes of the Incremental Auctions, the Forecast Pool Requirement multiplied by the updated PJM Region Peak Load Forecast, less the sum of all updated Unforced Capacity Obligations of FRR Entities in the PJM Region.

2.56 Projected PJM Market Revenues

"Projected PJM Market Revenues" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.57 Qualifying Transmission Upgrade

"Qualifying Transmission Upgrade" shall mean a proposed enhancement or addition to the Transmission System that: (a) will increase the Capacity Emergency Transfer Limit into an LDA by a megawatt quantity certified by the Office of the Interconnection; (b) the Office of the Interconnection has determined will be in service on or before the commencement of the first Delivery Year for which such upgrade is the subject of a Sell Offer in the Base Residual Auction; (c) is the subject of a Facilities Study Agreement executed before the conduct of the Base Residual Auction for such Delivery Year and (d) a New Service Customer is obligated to fund through a rate or charge specific to such facility or upgrade.

2.58 Reference Resource

"Reference Resource" shall mean a combustion turbine generating station, configured with two General Electric Frame 7FA turbines with inlet air cooling to 50 degrees, Selective Catalytic Reduction technology *in CONE Areas 1, 2, 3, and 4*, dual fuel capability, and a heat rate of *10.096* Mmbtu/ MWh.

2.59 Reliability Assurance Agreement

"Reliability Assurance Agreement" shall mean that certain "Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region," on file with FERC as PJM Interconnection, L.L.C. Rate Schedule FERC No.44.

2.60 Reliability Pricing Model Auction

"Reliability Pricing Model Auction" or "RPM Auction" shall mean the Base Residual Auction or any Incremental Auction.

2.61 Resource Substitution Charge

"Resource Substitution Charge" shall mean a charge assessed on Capacity Market Buyers in an Incremental Auction to recover the cost of replacement Capacity Resources.

2.61A Scheduled Incremental Auctions

"Scheduled Incremental Auctions" shall refer to the First, Second, or Third Incremental Auction.

2.62 Second Incremental Auction

"Second Incremental Auction" shall mean an Incremental Auction conducted ten months before the Delivery Year to which it relates.

2.63 Sell Offer

"Sell Offer" shall mean an offer to sell Capacity Resources in a Base Residual Auction, Incremental Auction, or Reliability Backstop Auction.

2.64 [Reserved for Future Use]

2.65 Self-Supply

"Self-Supply" shall mean Capacity Resources secured by a Load-Serving Entity, by ownership or contract, outside a Reliability Pricing Model Auction, and used to meet obligations under this Attachment or the Reliability Assurance Agreement through submission in a Base Residual Auction or an Incremental Auction of a Sell Offer indicating such Market Seller's intent that such Capacity Resource be Self-Supply. Self-Supply may be either committed regardless of clearing price or submitted as a Sell Offer with a price bid. A Load Serving Entity's Sell Offer with a price bid for an owned or contracted Capacity Resource shall not be deemed "Self-Supply," unless it is designated as Self-Supply and used by the LSE to meet obligations under this Attachment or the Reliability Assurance Agreement.

2.65A Short-Term Resource Procurement Target

"Short-Term Resource Procurement Target" shall mean, as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the

PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA.

2.65B Short-Term Resource Procurement Target Applicable Share

"Short-Term Resource Procurement Target Applicable Share" shall mean: (i) for the PJM Region, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction and, as to the Third Incremental Auction for the PJM Region, 0.6 times such target; and (ii) for an LDA, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction for such LDA and, as to the Third Incremental Auction, 0.6 times such target.

2.66 Third Incremental Auction

"Third Incremental Auction" shall mean an Incremental Auction conducted three months before the Delivery Year to which it relates.

2.67 Transition Adder

"Transition Adder" shall mean a component of a Sell Offer permitted for certain Capacity Market Sellers for the Transition Period, as set forth in section 17.

2.68 Transition Period

"Transition Period" shall mean the four-year period consisting of the Delivery Years commencing June 1, 2007, June 1, 2008, June 1, 2009, and June 1, 2010.

2.69 Unforced Capacity

"Unforced Capacity" shall have the meaning specified in the Reliability Assurance Agreement.

2.69A Updated VRR Curve

"Updated VRR Curve" shall mean the Variable Resource Requirement Curve as defined in section 5.10(a) of this Attachment for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect the Short-term Resource Procurement Target applicable to the relevant Incremental Auction and any change in the Reliability Requirement from the Base Residual Auction to such Incremental Auction.

2.69B 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.

2.69C 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.

2.70 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 Section 5.

2.71 Zonal Capacity Price

"Zonal Capacity Price" shall mean the clearing price required in each Zone to meet the demand for Unforced Capacity and satisfy Locational Deliverability Requirements for the LDA or LDAs associated with such Zone. If the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA.

5.8 Submission of Sell Offers and Buy Bids

Submission of Sell Offers and Buy Bids shall be subject to the following requirements:

a) A Sell Offer or Buy Bid that fails to specify a positive megawatt quantity shall be rejected by the Office of the Interconnection.

b) A Buy Bid that fails to specify price shall be rejected by the Office of the Interconnection. A Sell Offer that fails to either designate such offer as self-scheduled or to specify an offer price shall be rejected by the Office of the Interconnection.

c) A Buy Bid that fails to designate the type of Unforced Capacity desired, i.e., an Annual Resource, Extended Summer Demand Resource, or Limited Demand Resource, shall be rejected by the Office of the Interconnection.

d) All Sell Offers and Buy Bids must be received by the Office of the Interconnection during a specified period, as determined by the Office of the Interconnection, in accordance with the PJM Manuals. A Sell Offer or Buy Bid may be withdrawn by a notification of withdrawal received by the Office of the Interconnection at any time during the foregoing period, but may not be withdrawn after such period.

e) Sell Offers or Buy Bids shall be submitted or withdrawn via the Internet site designated by the Office of the Interconnection; provided, however, that if the Internet site cannot be accessed at any time during the period specified for the applicable auction, a Sell Offer or Buy Bid may be submitted or withdrawn by electronic mail transmitted to the e-mail address, or faxed to the fax number~~,~~ specified by the Office of the Interconnection ~~in the PJM Manuals~~.

f) Sell Offers must be based on the Capacity Market Seller's Capacity Resource position at the opening of the auction's bidding window.

g) The Office of the Interconnection shall accept a Sell Offer only up to the megawatt amount of installed capacity of Capacity Resources owned or controlled by such Capacity Market Seller that has not previously been committed for the applicable Delivery Year.

h) No Sell Offer shall be accepted from an FRR Entity unless it meets the requirements applicable to such offers under Schedule 8.1 of the Reliability Assurance Agreement.

i) The Office of the Interconnection shall have final authority to determine whether to accept a Sell Offer in accordance with the terms of the Tariff and the PJM Manuals.

5.15 Capacity Transfer Rights

(a) To recognize the value of Import Capability and provide a partial offset to potential Locational Price Adders that may be determined for an LDA (as to any Zone that encompasses two or more LDAs, the term "LDA" as used herein shall refer to such Zone, rather than to the LDAs it encompasses), the Office of the Interconnection shall allocate Capacity Transfer Rights to each LSE serving load in such LDA pro rata based on such LSE's Daily Unforced Capacity Obligation in such LDA. The total megawatts of Capacity Transfer Rights available for allocation shall equal the megawatts of Unforced Capacity imported into such LDA ~~as~~ determined ~~in~~ based on the results of the Base Residual Auction and Incremental Auctions ("Capacity Imported"), less any megawatts of CETL increase into such LDA attributable to Qualifying Transmission Upgrades cleared in an RPM Auction and any Incremental Capacity Transfer Rights into such LDA allocated pursuant to section 5.16 (but not less than zero), and shall be subject to change in subsequent Delivery Years as a result of changes in the quantity of such Capacity Imported into such LDA. Each change in an LSE's Daily Unforced Capacity Obligation during a Delivery Year shall result in a corresponding change in the Capacity Transfer Rights allocated to such LSE.

(b) ~~For purposes of any Base Residual Auction in an LDA~~ For LDAs ~~that~~ in which the RPM Auctions for the Delivery Year result~~s~~ed in a positive average weighted Locational Price Adder with respect to the immediate higher level LDA, the holder of the Capacity Transfer Rights in such LDA shall receive a payment during the Delivery Year equal to (i) the average weighted Locational Price Adder for such LDA determined with respect to the immediate higher level LDA as a result of ~~such~~all RPM ~~a~~Auctions for such Delivery Year~~for such LDA minus the Locational Price Adder for the LDA from which Unforced Capacity is imported to determine the Capacity Transfer Right~~, multiplied by (ii) the megawatt quantity of the Capacity Transfer Right allocated to such LSE in such LDA.

~~(c) For purposes of any Incremental Auction in such LDA that results in a positive Locational Price Adder, the holder of a Capacity Transfer Right shall receive a payment during the Delivery Year equal to the difference between the charges for the incremental Daily Unforced Capacity Obligation and the credits to be paid to the incremental Unforced Capacity cleared in the LDA plus incremental Unforced Capacity imported.~~

~~(d) Where an LDA is entirely contained within another LDA, a portion of the larger LDA Capacity Transfer Rights will be allocated to the smaller LDA, based on the smaller LDA's proportion of the larger zone's unforced capacity obligation. LDA remaining for determination of further credits will be reduced by the allocation of credits attributable to Capacity Imported into the larger LDA.~~

(~~e~~c) Capacity Transfer Rights shall be transferable. A purchaser of Capacity Transfer Rights from the original party allocated such rights shall receive any payments due under this section or section 5.16, provided the seller and purchaser of such rights timely notify the Office

of the Interconnection of such purchase, in accordance with procedures specified in the PJM manuals.

5.16 Incremental Capacity Transfer Rights

(a) The Office of the Interconnection shall allocate Incremental Capacity Transfer Rights to a New Service Customer (or, for facilities or upgrades in a PJM queue prior to March 1, 2007, to an Interconnection Customer) obligated to fund a transmission facility or upgrade through a rate or charge specific to such facility or upgrade, to the extent such upgrade or facility increases the Import Capability into a Locational Deliverability Area, with respect to any such transmission facility or upgrade interconnected to the Transmission System pursuant to Part IV of this Tariff, including transmission facilities or upgrades interconnected to the Transmission System pursuant to Part IV prior to the effective date of this Attachment. Incremental Capacity Transfer Rights shall be available for a facility or upgrade for a Delivery Year only if the Office of the Interconnection certifies the quantity of Import Capability provided by such facility or upgrade at least 45 days prior to the Base Residual Auction for such Delivery Year. The megawatt quantity of Incremental Capacity Transfer Rights allocated to such a New Service Customer (or Interconnection Customer) shall equal the megawatt quantity of the increase in Import Capability across a locational constraint resulting from such upgrade or facility, provided that the total Incremental Capacity Transfer Rights awarded as to an LDA (including those allocated pursuant to Schedule 12A of the Tariff) may not exceed the total Capacity Transfer Rights determined as to such LDA. A Capacity Market Seller that offers and clears a Qualifying Transmission Upgrade in the Base Residual Auction for a Delivery Year shall not receive Incremental Capacity Transfer Rights with respect to such upgrade for such Delivery Year. Terms and conditions for the allocation of Incremental Capacity Transfer Rights to New Service Customers shall be as further set forth in Part VI of this Tariff, and those for the allocation of Incremental Capacity Transfer Rights to Responsible Customers shall be as further set forth in Schedule 12A of this Tariff.

(b) For LDAs in which ~~any Base Residual or Incremental~~ the RPM Auctions for such Delivery Year ~~that~~ results in a positive average weighted Locational Price Adder ~~for such LDA~~ with respect to the immediate higher level LDA, the holder of an Incremental Capacity Transfer Right into such LDA shall receive a payment equal to the average weighted Locational Price Adder for the LDA into which the associated facility or upgrade increased Import Capability ~~minus the Locational Price Adder for the LDA from which the Import Capability increase was measured~~, multiplied by the megawatt quantity of the Incremental Capacity Transfer Right allocated to such Interconnection Customer.

6. MARKET POWER MITIGATION

6.1 Applicability

The provisions of the Market Monitoring Plan (in Attachment M and Attachment - M Appendix to this Tariff and this section 6) shall apply to the Reliability Pricing Model Auctions.

6.2 Process

(a) By no later than 90 days (or such other time period as established for purposes of the Transition Period) prior to the conduct of the Base Residual Auction and each Incremental Auction for such Delivery Year, the Office of the Interconnection shall post or continue to post the results of the Market Monitoring Unit's application of the Preliminary Market Structure Screen determined pursuant to section II.D of Attachment M - Appendix.

(b) In accordance with the schedule specified in the PJM Manuals, following PJM's conduct of a Base Residual Auction or Incremental Auction pursuant to section 5.12, but prior to the Office of the Interconnection's final determination of clearing prices and charges pursuant to section 5.14, the Office of the Interconnection shall: (i) apply the Market Structure Test to any LDA having a Locational Price Adder greater than zero and to the entire PJM region; (ii) apply Market Seller Offer Caps, if required under this section 6; and (iii) recompute the optimization algorithm to clear the auction with the Market Seller Offer Caps in place.

(c) Within seven days after the deadline for submission of Sell Offers in a Base Residual Auction or Incremental Auction, the Office of the Interconnection shall file with FERC a report of any determination made pursuant to sections 5.14(h), 6.5(a)(ii), or 6.7(c) identified in such sections as subject to the procedures of this section. Such report shall list each such determination, the information considered in making each such determination, and an explanation of each such determination. Any entity that objects to any such determination may file a written objection with FERC no later than seven days after the filing of the report. Any such objection must not merely allege that the determination was in error, and must provide support for the objection, demonstrating that the determination overlooked or failed to consider relevant evidence. In the event that no objection is filed, the determination shall be final. In the event that an objection is filed, FERC shall issue any decision modifying the determination no later than 60 days after the filing of such report; otherwise, the determination shall be final. Final auction results shall reflect any decision made by FERC regarding the report.

6.3 Market Structure Tests

(a) Preliminary Market Structure Screen.

The Market Monitoring Unit shall apply the Preliminary Market Structure Screen pursuant to section II.D of Attachment M - Appendix. Potential Capacity Market Sellers owning or controlling any ~~existing~~ Existing Generation Capacity Resources in the PJM Region shall be required to provide to the Market Monitoring Unit the additional information specified in section II.D of Attachment M - Appendix if such Generation Capacity is located in an LDA, "Unconstrained LDA Group" (as defined in Attachment M - Appendix), or the entire PJM

Region that fails the Preliminary Market Structure Screen, as applied pursuant to section II.D below.

(b) Market Structure Test.

A constrained LDA or the PJM Region shall fail the Market Structure Test, and mitigation shall be applied to all jointly pivotal suppliers (including all Affiliates of such suppliers, and all third-party supply in the relevant LDA controlled by such suppliers by contract), if, as to the Sell Offers that comprise the incremental supply determined pursuant to section 6.3(c) that are based on Generation Capacity Resources, there are not more than three jointly pivotal suppliers. The Office of the Interconnection shall apply the Market Structure Test. The Office of the Interconnection shall confirm the results of the Market Structure Test with the Market Monitoring Unit.

(c) Determination of Incremental Supply

In applying the Market Structure Test, the Office of the Interconnection shall consider all (i) incremental supply (provided, however, that the Office of the Interconnection shall consider only such supply available from Generation Capacity Resources) available to solve the constraint applicable to a constrained LDA offered at less than or equal to 150% of the cost-based clearing price; or (ii) supply for the PJM Region, offered at less than or equal to 150% of the cost-based clearing price, provided that supply in this section includes only the lower of cost-based or priced based offers from Generation Capacity Resources. Cost-based clearing prices are the prices resulting from the RPM auction algorithm using the lower of cost-based or price-based offers for all Capacity Resources.

6.4 Market Seller Offer Caps

(a) The Market Seller Offer Cap, stated in dollars per MW-day of ~~installed~~ unforced capacity, applicable to price-quantity offers within the Base Offer Segment for an ~~existing~~ Existing Generation Capacity Resource shall be the Avoidable Cost Rate for such resource, less the Projected PJM Market Revenues for such resource, stated in dollars per MW of unforced capacity. During the first three Delivery Years of the Transition Period, the Market Seller Offer Cap shall be increased for Sell Offers submitted by eligible Capacity Market Sellers in any Unconstrained LDA Group by the Transition Adder set forth in section 17.5 of this Attachment. The Market Seller Offer Cap for an ~~existing~~ Existing Generation Capacity Resource shall be the Opportunity Cost for such resource, if applicable, as determined in accordance with section 6.7. Nothing herein shall preclude any Capacity Market Seller and the Market Monitoring Unit from agreeing to, nor require either such entity to agree to, an alternative market seller offer cap determined on a mutually agreeable basis. Any such alternative offer cap shall be filed with the Commission for its approval. This provision is duplicated in section II.E.3 of Attachment M-Appendix.

(b) For each ~~existing~~ Existing Generation Capacity Resource, a potential Capacity Market Seller must timely provide to the Market Monitoring Unit data and documentation required under section 6.6 to establish the level of the Market Seller Offer Cap applicable to each resource. The Capacity Market Seller must promptly address any concerns identified by the

Market Monitoring Unit regarding the data and documentation provided, review the proposed Market Seller Offer Cap, and attempt to reach agreement with the Market Monitoring Unit on the level of the Market Seller Offer Cap.

(c) If the Market Monitoring Unit informs the Office of the Interconnection that a Capacity Market Seller has failed to submit costs consistent with section 6.7, it shall be required to submit any Sell Offer in the applicable auction as Self-Supply committed regardless of clearing price. If such Capacity Market Seller submits a Sell Offer that is not Self-Supply committed regardless of clearing price, the Market Monitoring Unit may seek relief from the Commission pursuant to section II.E of Attachment M - Appendix.

(d) In the event that a Capacity Market Seller and the Market Monitoring Unit cannot agree on the level of a Market Seller Offer Cap, the Office of the Interconnection shall make its own determination of the level of the Market Seller Offer Cap based on the requirements of the Tariff and the PJM Manuals. If the Capacity Market Seller submits a Sell Offer that the Office of the Interconnection determines would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction compared to the Office of the Interconnection's determination of the level of the Market Seller Offer Cap, the Office of the Interconnection shall apply to FERC for an order, on an expedited basis, directing such Capacity Market Seller to submit a Sell Offer consistent with the Office of the Interconnection's determination, or for other appropriate relief, and PJM shall postpone clearing the auction pending FERC's decision on the matter. Should the Market Monitoring Unit exercise its powers to inform Commission staff of its concerns and request a determination, on an expedited basis, directing a Capacity Market Seller to submit a Sell Offer consistent with the Market Monitoring Unit's determination, or for other appropriate relief, pursuant to section II.E of Attachment M - Appendix, PJM may postpone clearing the auction pending FERC's decision on the matter.

(e) Nothing in this section precludes the Capacity Market Seller from filing a petition with FERC seeking a determination of whether the Sell Offer complies with the requirements of the Tariff.

(f) Notwithstanding the foregoing, a Capacity Market Seller may submit a Sell Offer that it chooses, provided that (i) it has participated in good faith with the process described in this section 6.4 and in section II.E of Attachment M - Appendix, (ii) the offer is no higher than the level defined in any agreement reached by the Capacity Market Seller and the Market Monitoring Unit that resulted from the foregoing process, and (iii) the offer is accepted by the Office of the Interconnection subject to the criteria set forth in the Tariff and the PJM Manuals.

(g) For any Third Incremental Auction, the Market Seller Offer Cap for an Existing Generation Capacity Resource shall be determined pursuant to paragraph (a) of this Section 6.4, or if elected by the Capacity Market Seller, shall be equal to 1.1 times the Capacity Resource Clearing Price in the Base Residual Auction for the relevant LDA and Delivery Year.

6.5 Mitigation

The Office of the Interconnection shall apply market power mitigation measures in any Base Residual Auction or Incremental Auction for any LDA, Unconstrained LDA Group, or the PJM Region that fails the Market Structure Test.

(a) Mitigation for Generation Capacity Resources.

i) Existing Generation Capacity Resource

Mitigation will be applied on a unit-specific basis and only if the Sell Offer of Unforced Capacity from an Existing Generation Capacity Resource: (1) is greater than the Market Seller Offer Cap applicable to such resource; and (2) would, absent mitigation, increase the Capacity Resource Clearing Price in the relevant auction. If such conditions are met, such Sell Offer shall be set equal to the Market Seller Offer Cap.

ii) Planned Generation Capacity Resources

(A) Sell Offers based on Planned Generation Capacity Resources (including External Planned Generation Capacity Resources) shall be presumed to be competitive and shall not be subject to market power mitigation in any Base Residual Auction or Incremental Auction for which such resource qualifies as a Planned Generation Capacity Resource, but any such Sell Offer shall be rejected if it meets the criteria set forth in subsection (C) below, unless the Capacity Market Seller obtains approval from FERC for use of such offer prior to the deadline for submission of such offers in the applicable auction. Such resources are Existing Generation Capacity Resources in the auctions for any Delivery Year following the Delivery Year for which such resource cleared an RPM Auction. Such resources may receive certain price assurances for the two Delivery Years immediately following the first Delivery Year of service under certain conditions as set forth in section 5.14 of this Attachment. Notwithstanding the foregoing, a Generation Capacity Resource for which construction has not commenced and which would otherwise have been treated as a Planned Generation Capacity Resource but for the fact that it was bid into RPM Auctions for at least two consecutive Delivery Years, and cleared the last such auction only because it was considered existing and its mitigated offer cap was accepted when its price offer would not have otherwise been accepted, shall be deemed to be a Planned Generation Capacity Resource.

(B) Sell Offers based on Planned Generation Capacity Resources (including External Planned Generation Capacity Resources) submitted for the first year in which such resources qualify as Planned Generation Capacity Resources shall be deemed competitive and not be subject to mitigation if: (1) collectively all such Sell Offers provide Unforced Capacity in an amount equal to or greater than two times the incremental quantity of new entry required to meet the LDA Reliability Requirement; and (2) at least two unaffiliated suppliers have submitted Sell Offers for Planned Generation Capacity Resources in such LDA. Notwithstanding

the foregoing, any Capacity Market Seller, together with Affiliates, whose Sell Offers based on Planned Generation Capacity Resources in that LDA are pivotal, shall be subject to mitigation.

(C) Where the two conditions stated in subsection (B) are not met, or the Sell Offer is pivotal, the Sell Offer shall be rejected if it exceeds 140 percent of: 1) the average of location-adjusted Sell Offers for Planned Generation Capacity Resources from the same asset class as such Sell Offer, submitted (and not rejected) (Asset-Class New Plant Offers) for such Delivery Year; or 2) if there are no Asset-Class New Plant Offers for such Delivery Year, the average of Asset-Class New Plant Offers for all prior Delivery Years; or 3) if there are no Asset-Class New Plant Offers for any prior Delivery Year, the Net CONE applicable for such Delivery Year in the LDA for which such offer was submitted. For purposes of this section, asset classes shall be as stated in section 6.7(c) as effective for such Delivery Year, and Asset-Class New Plant Offers shall be location-adjusted by the ratio between the Net CONE effective for such Delivery Year for the LDA in which the Sell Offer subject to this section was submitted and the average, weighted by installed capacity, of the Net CONEs for all LDAs in which the units underlying such Asset Class New Plant Offers are located. Following the conduct of the applicable auction and before the final determination of clearing prices, in accordance with Section 6.2(b) above, each Capacity Market Seller whose Sell Offer is so rejected shall be notified and allowed an opportunity to submit a revised Sell Offer that does not exceed such threshold. The Office of the Interconnection then shall clear the auction with such revised Sell Offer in place.

(b) Mitigation for Demand Resources

The Market Seller Offer Cap shall not be applied to Sell Offers of Demand Resources or Energy Efficiency Resources.

6.6 Offer Requirement for Capacity Resources

(a) To avoid application of subsection (h), all of the installed capacity of all Existing Generation Capacity Resources located in the PJM Region shall be offered by the Capacity Market Seller that owns or controls all or part of such resource (which may include submission as Self-Supply) in all RPM Auctions for each Delivery Year, less any amount determined by the Office of the Interconnection to be eligible for an exception to the must-offer requirement, where installed capacity is determined as of the date on which bidding commences for each RPM Auction pursuant to Section 5.6.6 of Attachment DD of the Tariff. The Unforced Capacity of such resources is determined using the EFORd value that is submitted by the Capacity Market Seller in its Sell Offer, which shall not exceed the maximum EFORd for that resource as defined in Section 6.6(b). If a resource should be included on the list of Existing Generation Capacity Resources subject to the must-offer requirement that is maintained by the Market Monitoring Unit pursuant to Section II.C.1 of Attachment M – Appendix of the Tariff, but is omitted

therefrom whether by mistake of the Market Monitoring Unit or failure of the Capacity Market Seller that owns or controls all or part of such resource to provide information about the resource to the Market Monitoring Unit, this shall not excuse such resource from the must-offer requirement.

(b) For each Existing Generation Capacity Resource, a potential Capacity Market Seller must timely provide to the Market Monitoring Unit data and documentation required under section 6.6 to establish the maximum EFORd applicable to each resource. The maximum EFORd that may be used in a Sell Offer for Base Residual Auctions, First Incremental Auctions and Second Incremental Auctions, and for Conditional Incremental Auctions held prior to the date on which the final EFORds used for a Delivery Year are posted, is the greater of (i) the average EFORd for the five consecutive years ending on the September 30 that last precedes the Base Residual Auction, or (ii) the EFORd for the 12 months ending on the September 30 that last precedes the Base Residual Auction. The maximum EFORd that may be used in a Sell Offer for Third Incremental Auctions, and for Conditional Incremental Auctions held after the date on which the final EFORd used for a Delivery Year is posted, is the EFORd for the 12 months ending on the September 30 that last precedes the submission of such offers. The Capacity Market Seller must promptly address any concerns identified by the Market Monitoring Unit regarding the data and documentation provided, review the proposed maximum EFORd, and attempt to reach agreement with the Market Monitoring Unit on the maximum level of the EFORd

(c) If the Market Monitoring Unit informs the Office of the Interconnection that a Capacity Market Seller has failed to submit costs consistent with section 6.7, it shall be required to submit any Sell Offer in the applicable auction as Self-Supply committed regardless of clearing price. If such Capacity Market Seller submits a Sell Offer that is not Self-Supply committed regardless of clearing price, the Market Monitoring Unit may seek relief from the Commission pursuant to section 6.4(d) below and section II.E of Attachment M - Appendix.

(d) In the event that a Capacity Market Seller and the Market Monitoring Unit cannot agree on the maximum level of the EFORd, the Office of the Interconnection shall make its own determination of the maximum level of the EFORd based on the requirements of the Tariff and the PJM Manuals. If the Capacity Market Seller submits an EFORd that the Office of the Interconnection determines would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction compared to the Office of the Interconnection's determination of the maximum level of the EFORd, the Office of the Interconnection shall apply to FERC for an order, on an expedited basis, directing such Capacity Market Seller to submit an EFORd consistent with the Market Monitoring Unit's determination, or for other appropriate relief, and PJM shall postpone clearing the auction pending FERC's decision on the matter. Should the Market Monitoring Unit exercise its powers to inform Commission staff of its concerns and request a determination, on an expedited basis, directing a Capacity Market Seller to submit an EFORd consistent with the Market Monitoring Unit's determination, or for other appropriate relief, pursuant to section II.C of Attachment M - Appendix, PJM may postpone clearing the auction pending FERC's decision on the matter.

(e) Nothing in this section precludes the Capacity Market Seller from filing a petition with FERC seeking a determination of whether the EFORd complies with the requirements of the Tariff.

(f) Notwithstanding the foregoing, a Capacity Market Seller may submit an EFORd that it chooses, provided that (i) it has participated in good faith with the process described in this section 6.6 and in section II.C of Attachment M - Appendix, (ii) the offer is no higher than the level defined in any agreement reached by the Capacity Market Seller and the Market Monitoring Unit that resulted from the foregoing process, and (iii) the offer is accepted by the Office of the Interconnection subject to the criteria set forth in the Tariff and the PJM Manuals.

(g) A Capacity Market Seller that owns or controls an existing generation resource in the PJM Region that is capable of qualifying as an Existing Generation Capacity Resource as of the date on which bidding commences for an RPM Auction may not avoid the rule in subsection (a) or be removed from Capacity Resource status by failing to qualify as a Generation Capacity Resource, or by attempting to remove a unit previously qualified as a Generation Capacity Resource from classification as a Capacity Resource for that RPM Auction.However, generation resource may qualify for an exception to the must-offer requirement, as shown by appropriate documentation, if the Capacity Market Seller that owns or controls such resource demonstrates that it: (i) is reasonably expected to be physically unable to participate in the relevant Delivery Year; (ii) has a financially and physically firm commitment to an external sale of its capacity, or (iii) was interconnected to the Transmission System as an Energy Resource and not subsequently converted to a Capacity Resource.

In order to establish that a resource is reasonably expected to be physically unable to participate in the relevant auction as set forth in (i) above, the Capacity Market Seller must demonstrate that:

A. It has a documented plan in place to retire the resource prior to or during the Delivery Year, and has submitted a notice of Deactivation to the Office of the Interconnection consistent with Section 113.1 of the PJM Tariff, without regard to whether the Office of the Interconnection has requested the Capacity Market Seller to continue to operate the resource beyond its desired deactivation date in accordance with Section 113.2 of the PJM Tariff for the purpose of maintaining the reliability of the PJM Transmission System and the Capacity Market Seller has agreed to do so;

B. Significant physical operational restrictions cause long term or permanent changes to the installed capacity value of the resource, or the resource is under major repair that will extend into the applicable Delivery Year, that will result in the imposition of RPM performance penalties pursuant to Attachment DD of the PJM Tariff;

C. The Capacity Market Seller is involved in an ongoing regulatory proceeding (e.g. – regarding potential environmental restrictions) specific to the resource and has received an order, decision, final rule, opinion or other final directive from the regulatory authority that will result in the retirement of the resource; or

D. A resource considered an Existing Generating Capacity Resource because it cleared an RPM Auction for a Delivery Year prior to the Delivery Year of the relevant auction, but which is not yet in service, is unable to achieve full commercial operation prior to the Delivery Year of the relevant auction. The Capacity Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer certifying that the resource will not be in full commercial operation prior to the referenced Delivery Year.

In order to establish that a resource has a financially and physically firm commitment to an external sale of its capacity as set forth in (ii) above, the Capacity Market Seller must demonstrate that it has entered into a unit-specific bilateral transaction for service to load located outside the PJM Region, by a demonstration that such resource is identified on a unit-specific basis as a network resource under the transmission tariff for the control area applicable to such external load, or by an equivalent demonstration of a financially and physically firm commitment to an external sale. The Capacity Market Seller additionally shall identify the megawatt amount, export zone, and time period (in days) of the export.

A Capacity Market Seller that seeks to remove a Generation Capacity Resource from PJM Capacity Resource status and/or seeks approval for an exception to the must-offer requirement shall first submit such request to the Market Monitoring Unit for evaluation. A Capacity Market Seller may only remove the Generation Capacity Resource from PJM Capacity Resource status if (i) the Market Monitoring Unit has determined that the Generation Capacity Resource meets the applicable criteria set forth in Sections 5.6.6 and 6.6 of Attachment DD and the Office of the Interconnection agrees with this determination, or, (ii) the potential Capacity Market Seller and the Market Monitoring Unit cannot come to agreement on whether a Generation Capacity Resource should be removed from PJM Capacity Resource status or satisfied the criteria for an exception to the must-offer requirement, the potential Capacity Market Seller has submitted its request to remove the resource from PJM Capacity Resource status to the Office of the Interconnection, and the Office of the Interconnection has determined that the Generation Capacity Resource meets the applicable criteria set forth in Sections 5.6.6 and 6.6 of Attachment DD. Nothing herein shall require a Market Seller to offer its resource into an RPM Auction prior to seeking to remove a resource from Capacity Resource status, subject to satisfaction of Section 6.6.

After the Market Monitoring Unit has made its determination of whether a resource has satisfied the must-offer requirement or meets one of the exceptions thereto and has notified the Capacity Market Seller and the Office of the Interconnection of the same pursuant to Section II.C.4 of Attachment M – Appendix, the Office of the Interconnection shall approve or deny the exception request. The exception request shall be deemed to be approved or denied by the Office of the Interconnection, consistent with the determination of the Market Monitoring Unit, unless the Office of the Interconnection notifies the Capacity Market Seller and Market Monitoring Unit that it disagrees with the Market Monitoring Unit's determination. After the Market Monitoring Unit and the Office of the Interconnection have made their determinations of whether a resource meets the criteria to qualify for an exception to the must-offer requirement and prior to the date on which bidding commences for the applicable RPM Auction, the Capacity Market Seller must notify the Market Monitoring Unit and the Office of the Interconnection whether it intends to exclude from its Sell Offer some or all of the subject capacity on the basis

of an identified exception. PJM does not make determinations of whether withholding of capacity constitutes market power. A Generation Capacity Resource that does not qualify for submission into an RPM Auction because it is not owned or controlled by the Capacity Market Seller for a full Delivery Year is not subject to the offer requirement hereunder; provided, however, that a Capacity Market Seller planning to transfer ownership or control of a Generation Capacity Resource during a Delivery Year pursuant to a sale or transfer agreement shall be required to satisfy the offer requirement hereunder for the entirety of such Delivery Year and may satisfy such requirement by providing for the assumption of this requirement by the transferee of ownership or control under such agreement.

(h) Any existing generation resource located in the PJM Region that satisfies the criteria in the definition of Existing Generation Capacity Resource as of the date on which bidding commences for the Base Residual Auction for a Delivery Year, that is not offered into such Base Residual Auction, and that does not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any subsequent Incremental Auctions conducted for such Delivery Year; (ii) shall not receive any payments under section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

All generation resources located in the PJM Region that satisfy the criteria in the definition of Existing Generation Capacity Resource as of the date on which bidding commences for an Incremental Auction for a particular Delivery Year, but that did not satisfy such criteria as of the date that on which bidding commenced in the Base Residual Auction for that Delivery Year, that is not offered into that Incremental Auction, and that does not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any subsequent Incremental Auctions conducted for such Delivery Year; (ii) shall not receive any payments under section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

All Existing Generation Capacity Resources that are offered into a Base Residual Auction or Incremental Auction for a particular Delivery Year but do not clear in such auction, that are not offered into each subsequent Incremental Auction, and that do not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any Incremental Auctions conducted for such Delivery Year subsequent to such failure to offer; (ii) shall not receive any payments under section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

Any such Existing Generation Capacity Resources may also be subject to further action by the Market Monitoring Unit under the terms of Attachment M and Attachment M – Appendix.

(i) In addition to the remedies set forth in subsections (g) and (h) above, if the Market Monitoring Unit determines that one or more Capacity Market Sellers' failure to offer part or all of one or more existing generation resources, for which the Office of the Interconnection has not approved an exception to the must-offer requirement, into an RPM

Auction as required by this Section 6.6 would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction, and the Office of the Interconnection agrees with that determination, the Office of the Interconnection shall apply to FERC for an order, on an expedited basis, directing such Capacity Market Seller to participate in the relevant RPM Auction, or for other appropriate relief, and PJM will postpone clearing the auction pending FERC's decision on the matter. If the Office of the Interconnection disagrees with the Market Monitoring Unit's determination and does not apply to FERC for an order directing the Capacity Market Seller to participate in the auction or for other appropriate relief, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and to seek appropriate relief.

6.7 Data Submission

(a) Potential participants in any PJM Reliability Pricing Model Auction shall submit, together with supporting documentation for each item, to the Market Monitoring Unit no later than four months prior to the posted date for the conduct of such auction, a list of owned or controlled generation resources by PJM transmission zone for the specified Delivery Year, including the amount of gross capacity, the EFORd and the net (unforced) capacity.

(b) Except as provided in subsection (c) below, potential participants in any PJM Reliability Pricing Model Auction in any LDA or Unconstrained LDA Group that fails the Preliminary Market Structure Screen (or, if such region fails the screen, potential auction participants in the entire PJM Region) shall, in addition, submit the following data, together with supporting documentation for each item, to the Market Monitoring Unit no later than two months prior to the conduct of such auction:

i. If the Capacity Market Seller intends to submit a non-zero price in its Sell Offer in any such auction, the Capacity Market Seller shall submit a calculation of the Avoidable Cost Rate and Projected PJM Market Revenues, as defined in subsection (d) below, together with detailed supporting documentation.

ii. If the Capacity Market Seller intends to submit a Sell Offer based on opportunity cost, the Capacity Market Seller shall also submit a calculation of Opportunity Cost, as defined in subsection (d), with detailed supporting documentation.

(c) Potential auction participants identified in subsection (b) above need not submit the data specified in that subsection for any Generation Capacity Resource:

i. that is in an Unconstrained LDA Group or, if this is the relevant market, the entire PJM Region, and is in a resource class identified in the table below as not likely to include the marginal price-setting resources in such auction; or

ii. for which the potential participant commits that any Sell Offer it submits as to such resource shall not include any price above: (1) the level identified below for the relevant resource class, less (2) the Projected PJM Market Revenues for such resource, as determined in accordance with this Tariff.

Nothing herein precludes the Market Monitoring Unit from requesting additional information from any potential auction participant as deemed necessary by the Market Monitoring Unit, including, without limitation, additional cost data on resources in a class that is not otherwise expected to include the marginal price setting resource; and compliance with such request shall be a condition of participation in any auction. Any Sell Offer submitted in any auction that is inconsistent with any commitment made pursuant to this subsection shall be rejected, and the Capacity Market Seller shall be required promptly to resubmit a Sell Offer that complies with such commitments. If the Capacity Market Seller does not timely resubmit its Sell Offer, it shall be deemed to have submitted a Sell Offer that complies with the commitments made under this subsection, with a default price equal to the maximum price for the class of resource determined under section (c)(ii) above. The obligation imposed under section 6.6(a) shall not be satisfied unless and until the Capacity Market Seller submits (or is deemed to have submitted) a Sell Offer that conforms to its commitments made pursuant to this subsection or subject to the procedures set forth in section 6.4 and section II.H of Attachment M - Appendix. The default Avoidable Cost Rates referenced in section (c)(ii) above are as set forth in the tables below for any auction conducted after September 1, 2009 for any Delivery Year through the 2012-2013 Delivery Year. To determine the default ACR values for the 2013-2014 and subsequent Delivery Years, the Office of the Interconnection shall multiply the ACR values for the immediately preceding Delivery Year by a factor equal to the most recent ten-calendar-year annual average rate of change in the applicable Handy-Whitman Index of Public Utility Construction Costs or a comparable index approved by the Commission, as calculated by the Office of the Interconnection and posted to its Web site; provided, however, that after the Handy-Whitman indexing methodology has been employed to determine the default ACR values for the RPM Auctions for three consecutive Delivery Years, the Office of the Interconnection shall: i) review the default ACR values to determine whether any changes other than those produced by such methodology are warranted for subsequent Delivery Years (including seeking the analysis and advice of the Market Monitoring Unit on such matter) and report its conclusions to the Members in writing no later than four months after the Base Residual Auction for the third such Delivery Year; and ii) file with FERC resulting changes, if any, to this section no later than seven months after such Base Residual Auction, to be effective for the Base Residual Auction for the following Delivery Year; provided further, that nothing herein precludes the Office of the Interconnection from filing with FERC changes to the default ACR values or any other provision of this section prior to the deadline stated in the previous clause, or at any other time. Capacity Market Sellers shall use the one-year mothball Avoidable Cost Rate shown below, unless such Capacity Market Seller satisfies the criteria set forth in section 6.7(e), in which case the Capacity Market Seller may use the retirement Avoidable Cost Rate. PJM shall also publish on its Web site the number of Generation Capacity Resources and megawatts per LDA that use the retirement Avoidable Cost Rates.

Technology Classes Not Likely to be the Marginal Price Setting Resource						
Technology	**2010-2011 Mothball Avoidable Cost Rate ($/MW-Day)**	**2010-2011 Retirement Avoidable Cost Rate ($/MW-Day)**	**2011-2012 Mothball Avoidable Cost Rate ($/MW-Day)**	**2011-2012 Retirement Avoidable Cost Rate ($/MW-Day)**	**2012-2013 Mothball Avoidable Cost Rate ($/MW-Day)**	**2012 -2013 Retirement Avoidable Cost Rate ($/MW-Day)**
Nuclear	N/a	N/a	N/a	N/a	N/a	N/a
Pumped Storage	$20.77	$29.17	$21.72	$30.50	$22.71	$31.89
Hydro	$71.01	$92.87	$74.24	$97.10	$77.62	$101.52
Sub-Critical Coal	$170.48	$188.98	$178.24	$197.58	$186.35	$206.57
Super Critical Coal	$176.13	$192.65	$184.15	$201.42	$192.53	$210.59
Waste Coal - Small	$224.83	$272.31	$235.06	$284.70	$245.75	$297.65
Waste Coal – Large	$83.15	$100.45	$86.94	$105.02	$90.89	$109.80
Wind	N/a	N/a	N/a	N/a	N/a	N/a

Maximum Avoidable Cost Rates by Technology Class

Technology	2010-2011 Mothball Avoidable Cost Rate ($/MW-Day)	2010-2011 Retirement Avoidable Cost Rate ($/MW-Day)	2011-2012 Mothball Avoidable Cost Rate ($/MW-Day)	2011-2012 Retirement Avoidable Cost Rate ($/MW-Day)	2012-2013 Mothball Avoidable Cost Rate ($/MW-Day)	2012-2013 Retirement Avoidable Cost Rate ($/MW-Day)
CC- 2 on 1 Frame F	$30.92	$43.86	$32.33	$45.85	$33.80	$47.94
CC- 3 on 1 Frame E/Siemens	$34.33	$46.48	$35.89	$48.60	$37.52	$50.81
CC – 3 or More on 1 or More Frame F	$26.76	$37.16	$27.98	$38.85	$29.26	$40.62
CC-NUG Cogen. Frame B or E Technology	$114.93	$154.43	$120.16	$161.45	$125.62	$168.80
CT - 1st & 2nd Gen. Aero (P&W FT 4)	$24.57	$32.68	$25.69	$34.17	$26.86	$35.73
CT - 1st & Gen. Frame B	$24.28	$32.41	$25.38	$33.87	$26.54	$35.42
CT - 2nd Gen. Frame E	$23.08	$30.89	$24.13	$32.29	$25.23	$33.76
CT - 3rd Gen. Aero (GE LM 6000)	$55.87	$82.36	$58.42	$86.10	$61.07	$90.02
CT - 3rd Gen. Aero (P&W FT - 8 TwinPak)	$29.30	$43.20	$30.64	$45.17	$32.03	$47.23
CT - 3rd Gen. Frame F	$23.69	$34.12	$24.77	$35.68	$25.90	$37.30
Diesel	$26.29	$33.39	$27.49	$34.91	$28.74	$36.49
Oil and Gas Steam	$65.21	$79.39	$68.18	$83.01	$71.28	$86.78

After the Market Monitoring Unit conducts its annual review of the table of default Avoided Cost Rates included in section 6.7(c) above in accordance with the procedure specified in section II.H of Attachment M – Appendix, it will provide updated values or notice of its determination that updated values are not needed to Office of the Interconnection. In the event that the Office of the Interconnection disagrees with the values proposed for revising the matrix, the Office of the Interconnection shall file its values.

(d) In order for costs to qualify for inclusion in the Market Seller Offer Cap, the Capacity Market Seller must provide to the Market Monitoring Unit relevant cost data concerning each data item specified as set forth in section 6. If cost data is not available at the time of submission for the time periods specified in section 6.8, costs may be estimated for such period based on the most recent data available, with an explanation of and basis for the estimate used. Based on the data and calculations submitted by the Capacity Market Sellers for each existing generation resource and the formulas specified below, the Market Monitoring Unit shall calculate the Market Seller Offer Cap for each such resource, and notify the Capacity Market Seller one month prior to the auction of its determination.

i. Avoidable Cost Rate: The Avoidable Cost Rate for an existing generation resource shall be determined using the formula below and applied to the unit's Base Offer Segment.

ii. Opportunity Cost: Opportunity Cost shall be the documented price available to an existing generation resource in a market external to PJM. In the event that the total MW of existing generation resources submitting opportunity cost offers in any auction for a Delivery Year exceeds the firm export capability of the PJM system for such Delivery Year, or the capability of external markets to import capacity in such year, the Office of the Interconnection will accept such offers on a competitive basis. PJM will construct a supply curve of opportunity cost offers, ordered by opportunity cost, and accept such offers to export starting with the highest opportunity cost, until the maximum level of such exports is reached. The maximum level of such exports is the lesser of the Office of the Interconnection's ability to permit firm exports or the ability of the importing area(s) to accept firm imports or imports of capacity, taking account of relevant export limitations by location. If, as a result, an opportunity cost offer is not accepted from an existing generation resource, the Market Seller Offer Cap applicable to Sell Offers relying on such generation resource shall be the Avoidable Cost Rate~~.~~ less the Projected Market Revenues for such resource (as defined in Section 6.4). The default Avoidable Cost Rate shall be the one year mothball Avoidable Cost Rate set forth in the tables in section 6.7(c) above unless Capacity Market Seller satisfies the criteria delineated in section 6.7(e) below.

iii. Projected PJM Market Revenues, as defined by section 6.8(d), for any Generation Capacity Resource to which the Avoidable Cost Rate is applied.

(e) In order for the retirement Avoidable Cost Rate set forth in the table in section 6.7(c) to apply, a Capacity Market Seller must timely submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer representing that the Capacity Market Seller will retire the Generation Capacity Resource if it does not receive during the relevant Delivery Year at least the applicable retirement Avoidable Cost Rate because it would be uneconomic to continue to operate the Generation Capacity Resource in the Delivery Year without the retirement Avoidable Cost Rate, and specifying the date the Generation Capacity Resource would otherwise be retired.

6.8 Avoidable Cost Definition

(a) **Avoidable Cost Rate**:

The Avoidable Cost Rate for a Generation Capacity Resource that is the subject of a Sell Offer shall be determined using the following formula, expressed in dollars per MW-year:

Avoidable Cost Rate = [Adjustment Factor * (AOML + AAE + AME + AVE + ATFI + ACC + ACLE) + ARPIR + APIR]

Where:

- **Adjustment Factor** equals 1.10 (to provide a margin of error for understatement of costs) plus an additional adjustment referencing the 10-year average Handy-Whitman Index in order to account for expected inflation from the time interval between the submission of the Sell Offer and the commencement of the Delivery Year.

- **AOML (Avoidable Operations and Maintenance Labor)** consists of the avoidable labor expenses related directly to operations and maintenance of the generating unit for the twelve months preceding the month in which the data must be provided. The categories of expenses included in AOML are those incurred for: (a) on-site based labor engaged in operations and maintenance activities; (b) off-site based labor engaged in on-site operations and maintenance activities directly related to the generating unit; and (c) off-site based labor engaged in off-site operations and maintenance activities directly related to generating unit equipment removed from the generating unit site.

    - **AAE (Avoidable Administrative Expenses)** consists of the avoidable administrative expenses related directly to employees at the generating unit for twelve months preceding the month in which the data must be provided. The categories of expenses included in AAE are those incurred for: (a) employee expenses (except employee expenses included in AOML); (b) environmental fees; (c) safety and operator training; (d) office supplies; (e) communications; and (f) annual plant test, inspection and analysis.

    - **AME (Avoidable Maintenance Expenses)** consists of avoidable maintenance expenses (other than expenses included in AOML) related directly to the generating unit for the twelve months preceding the month in which the data must be provided. The categories of expenses included in AME are those incurred for: (a) chemical and materials consumed during maintenance of the generating unit; and (b) rented maintenance equipment used to maintain the generating unit.

    - **AVE (Avoidable Variable Expenses)** consists of avoidable variable expenses related directly to the generating unit incurred in the twelve months preceding the month in which the data must be provided. The categories of expenses included in AVE are those incurred for: (a) water treatment chemicals and lubricants; (b) water, gas, and electric service (not for power generation); and (c) waste water treatment.

    - **ATFI (Avoidable Taxes, Fees and Insurance)** consists of avoidable expenses related directly to the generating unit incurred in the twelve months preceding the month in which the data must be provided. The categories of expenses included in AFTI are those incurred for: (a) insurance, (b) permits and licensing fees, (c) site security and utilities for maintaining security at the site; and (d) property taxes.

- **ACC (Avoidable Carrying Charges)** consists of avoidable short-term carrying charges related directly to the generating unit in the twelve months preceding the month in which the data must be provided. Avoidable short-term carrying charges shall include short term carrying charges for maintaining reasonable levels of inventories of fuel and spare parts that result from short-term operational unit decisions as measured by industry best practice standards. For the purpose of determining ACC, short term is the time period in which a reasonable replacement of inventory for normal, expected operations can occur.

- **ACLE (Avoidable Corporate Level Expenses)** consists of avoidable corporate level expenses directly related to the generating unit incurred in the twelve months preceding the month in which the data must be provided. Avoidable corporate level expenses shall include only such expenses that are directly linked to providing tangible services required for the operation of the generating unit proposed for Deactivation. The categories of avoidable expenses included in ACLE are those incurred for: (a) legal services, (b) environmental reporting; and (c) procurement expenses.

- **APIR (Avoidable Project Investment Recovery Rate) = PI * CRF**

Where:

- **PI** is the amount of project investment completed prior to June 1 of the Delivery Year, except for Mandatory Capital Expenditures ("CapEx") for which the project investment must be completed during the Delivery Year, that is reasonably required to enable a Generation Capacity Resource that is the subject of a Sell Offer to continue operating or improve availability during Peak-Hour Periods during the Delivery Year.

- **CRF** is the annual capital recovery factor from the following table, applied in accordance with the terms specified below.

Age of Existing Units (Years)	Remaining Life of Plant (Years)	Levelized CRF
1 to 5	30	0.107
6 to 10	25	0.114
11 to 15	20	0.125
16 to 20	15	0.146
21 to 25	10	0.198
25 Plus	5	0.363
Mandatory CapEx	4	0.450

40 Plus Alternative	1	1.100

Unless otherwise stated, Age of Existing Unit shall be equal to the number of years since the Unit commenced commercial operation, up to and through the relevant Delivery Year.

Remaining Life of Plant defines the amortization schedule (i.e., the maximum number of years over which the Project Investment may be included in the Avoidable Cost Rate.)

Capital Expenditures and Project Investment

For any given Project Investment, a Capacity Market Seller may make a one-time election to recover such investment using: (i) the highest CRF and associated recovery schedule to which it is entitled; or (ii) the next highest CRF and associated recovery schedule. For these purposes, the CRF and recovery schedule for the ~~16~~ 25Plus category is the next highest CRF and recovery schedule for both the Mandatory CapEx and the 40 Plus Alternative categories. The Capacity Market Seller using the above table must provide the Market Monitoring Unit with information, identifying and supporting such election, including but not limited to the age of the unit, the amount of the Project Investment, the purpose of the investment, evidence of corporate commitment (e.g., an SEC filing, a press release, or a letter from a duly authorized corporate officer indicating intent to make such investment), and detailed information concerning the governmental requirement (if applicable). Absent other written notification, such election shall be deemed based on the CRF such Seller employs for the first Sell Offer reflecting recovery of any portion of such Project Investment. ~~A Sell Offer submitted in the BRA for either or both of the 2007/2008 and 2008/2009 Delivery Years for which the "16 Plus" CRF and recovery schedule is selected may not exceed an offer price equal to the then-current Net CONE (on an unforced-equivalent basis).~~

For any resource using the CRF and associated recovery schedule from the CRF table that set the Capacity Resource Clearing Price in any Delivery Year, such Capacity Market Seller must also provide to the Market Monitoring Unit, for informational purposes only, evidence of the actual expenditure of the Project Investment, when such information becomes available.

If the project associated with a Project Investment that was included in a Sell Offer using a CRF and associated recovery schedule from the above table has not entered into commercial operation prior to the end of the relevant Delivery Year, and the resource's Sell Offer sets the clearing price for the relevant LDA, the Capacity Market Seller shall be required to elect to either (i) pay a charge that is equal to the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the APIR component of the Avoidable Cost Rate, this difference to be multiplied by the cleared MW volume from such Resource ("rebate payment"); (ii) hold such rebate payment in escrow, to be released to the Capacity Market Seller in the event that the project enters into commercial operation during the subsequent Delivery Year or rebated to LSEs in the relevant LDA if the project has not entered into commercial operation during the subsequent Delivery Year; or (iii) make a reasonable investment in the amount of the PI in other ~~existing~~ Existing Generation Capacity Resources owned or controlled by the Capacity Market Seller or its Affiliates in the relevant LDA. The revenue from such rebate payments shall be allocated pro rata to LSEs in the

relevant LDA(s) that were charged a Locational Reliability Charge for such Delivery Year, based on their Daily Unforced Capacity Obligation in the relevant LDA(s). If the Sell Offer from the Generation Capacity Resource did not set the Capacity Resource Clearing Price in the relevant LDA, no alternative investment or rebate payment is required. If the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the APIR amount does not exceed the greater of $10 per MW-day or a 10% increase in the clearing price, no alternative investment or rebate payment is required.

Mandatory CapEx Option

The Mandatory CapEx CRF and recovery schedule is an option available, beginning in the third BRA (Delivery Year 2009-10), to a resource that must make a Project Investment to comply with a governmental requirement that would otherwise materially impact operating levels during the Delivery Year, where: (i) such resource is a coal, oil or gas-fired resource that began commercial operation no fewer than fifteen years prior to the start of the first Delivery Year for which such recovery is sought, and such Project Investment is equal to or exceeds $200/kW of capitalized project cost; or (ii) such resource is a coal-fired resource located in an LDA for which a separate VRR Curve has been established for the relevant Delivery Years, and began commercial operation at least 50 years prior to the conduct of the relevant BRA.

A Capacity Market Seller that wishes to elect the Mandatory CapEx option for a Project Investment must do so beginning with the Base Residual Auction for the Delivery Year in which such project is expected to enter commercial operation. A Sell Offer submitted in any Base Residual Auction for which the Mandatory CapEx option is selected may not exceed an offer price equivalent to 0.90 times the then-current Net CONE (on an unforced-equivalent basis).

40 ~~Year~~ Plus Alternative Option

The 40 Plus Alternative CRF and recovery schedule is an option available, beginning in the third BRA (Delivery Year 2009-10), for a resource that is a gas- or oil-fired resource that began commercial operation no less than 40 years prior to the conduct of the relevant BRA (excluding, however, any resource in any Delivery Year for which the resource is receiving a payment under Part V of the PJM Tariff. Generation Capacity Resources electing this 40 Plus Alternative CRF shall be treated as At Risk Generation for purposes of the sensitivity runs in the RTEP process). Resources electing the 40 ~~Year~~ Plus Alternative ~~O~~option will be modeled in the RTEP process as "at-risk" at the end of the one-year amortization period.

A Capacity Market Seller that wishes to elect the 40 Plus Alternative option for a Project Investment must provide written notice of such election to the Office of the Interconnection no later than six months prior to the Base Residual Auction for which such election is sought; provided however that shorter notice may be provided if unforeseen circumstances give rise to the need to make such election and such seller gives notice as soon as practicable.

The Office of the Interconnection shall give market participants reasonable notice of such election, subject to satisfaction of requirements under the PJM Operating Agreement for

protection of confidential and commercially sensitive information. A Sell Offer submitted in any Base Residual Auction for which the 40 Plus Alternative option is selected may not exceed an offer price equivalent to the then-current Net CONE (on an unforced-equivalent basis).

Multi-Year Pricing Option

A Seller submitting a Sell Offer with an APIR component that is based on a Project Investment of at least $450/kW may elect this Multi-Year Pricing Option by providing written notice to such effect the first time it submits a Sell Offer that includes an APIR component for such Project Investment. Such option shall be available on the same terms, and under the same conditions, as are available to Planned Generation Capacity Resources under section 5.14(c) of this Attachment.

- ARPIR (Avoidable Refunds of Project Investment Reimbursements) consists of avoidable refund amounts of Project Investment Reimbursements payable by a Generation Owner to PJM under Part V, Section 118 of this Tariff or avoidable refund amounts of project investment reimbursements payable by a Generation Owner to PJM under a Cost of Service Recovery Rate filed under Part V, Section 119 of the Tariff and approved by the Commission.

(b) For the purpose of determining an Avoidable Cost Rate, avoidable expenses are incremental expenses directly required to operate a Generation Capacity Resource that a Generation Owner would not incur if such generating unit did not operate in the Delivery Year or meet Availability criteria during Peak-Hour Periods during the Delivery Year.

(c) For the purpose of determining an Avoidable Cost Rate, avoidable expenses shall exclude variable costs recoverable under cost-based offers to sell energy from operating capacity on the PJM Interchange Energy Market under the Operating Agreement.

(d) Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied shall include all actual unit-specific revenues from PJM energy markets, ancillary services, and unit-specific bilateral contracts from such Generation Capacity Resource, net of marginal costs for providing such energy (i.e., costs allowed under cost-based offers pursuant to Section 6.4 of Schedule 1 of the Operating Agreement) and ancillary services from such resource.

(i) For the first three BRAs (for Delivery Years 2007-08, 2008-09, 2009-10), the calculation of Projected PJM Market Revenues shall be equal to the simple average of such net revenues as described above for calendar years 2001-2006; and

(ii) For the fourth BRA (delivery year 2010-11) and thereafter, the calculation of Projected PJM Market Revenues shall be equal to the rolling simple average of such net

revenues as described above from the three most recent whole calendar years prior to the year in which the BRA is conducted.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because the Generation Capacity Resource was not integrated into PJM during the full period, then the Projected PJM Market Revenues shall be calculated using only those whole calendar years within the full period in which such Resource received PJM market revenues.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because it was not in commercial operation during the entire period, or if data is not available to the Capacity Market Seller for the entire period, despite the good faith efforts of such seller to obtain such data, then the Projected PJM Market Revenues shall be calculated based upon net revenues received over the entire period by comparable units, to be developed by the MMU and the Capacity Market Seller.

8. CAPACITY RESOURCE DEFICIENCY CHARGE

8.1

A Capacity Resource Deficiency Charge shall be assessed on any Capacity Market Seller that commits a Capacity Resource, and on any Locational UCAP Seller that sells Locational UCAP for a Delivery Year based on a Generation Capacity Resource, for a Delivery Year that is unable or unavailable to deliver Unforced Capacity for all or any part of such Delivery Year for any reason, including but not limited to the following, and that does not obtain replacement Unforced Capacity meeting the same locational requirements and same or better temporal availability characteristics (i.e., Annual Resource, Extended Summer Demand Resource, or Limited Demand Resource) in the megawatt quantity required to satisfy the capacity committed from such resource by such seller as a result of all cleared Sell Offers from such seller based on such resource in any RPM Auctions for such Delivery Year, the reduction in any such commitment for such resource to the extent and for the time period of any replacement capacity committed in lieu of such resource, and the increase in any such commitment for such resource to the extent and for the time period that such resource is committed as replacement capacity for any other resource:

a) Unit Derating – Such Capacity Resource is a Generation Capacity Resource and its capacity value is derated prior to or during the Delivery Year;

b) EFORD Increase – Such Capacity Resource is a Generation Capacity Resource and the EFORD value determined for such resource at least two (2) months prior to the Third Incremental Auction is higher than the EFORD value submitted in the Capacity Market Seller's cleared Sell Offer;

c) External Generation Resource – Such Capacity Resource is an ~~existing~~ Existing Generation Capacity Resource that is located outside of the PJM Control Area and arrangements for the firm delivery of the output of such resource to the interface with the PJM Region are not in place for such resource prior to the start of the Delivery Year;

d) Planned Generation Resource – Such Capacity Resource is a Planned Generation Capacity Resource and Interconnection Service has not commenced as to such resource prior to the start of the Delivery Year;

e) Planned Demand Resource - Such Capacity Resource is a Planned Demand Resource or an Energy Efficiency Resource and the associated demand response program or energy efficiency measure is not installed prior to the start of the Delivery Year; or

f) Existing Demand Resource – Such Capacity Resource is an existing Demand Resource or Energy Efficiency Resource and, subject to section 8.4, is not capable of providing the megawatt quantity of load response specified in the cleared Sell Offer for the time periods of availability associated with the product type.

8.2. Capacity Resource Deficiency Charge

The Capacity Resource Deficiency Charge shall equal the Daily Deficiency Rate (as defined in section 7) multiplied by the megawatt quantity of deficiency below the level of capacity committed in such Capacity Market Seller's Sell Offer(s) or bilateral capacity commitments, or Locational UCAP Seller's Locational UCAP sale for each day such seller is deficient.

8.3. Allocation of Revenue Collected from Capacity Resource Deficiency Charges

The revenue collected from the assessment of a Capacity Resource Deficiency Charge shall be distributed on a pro-rata basis to all LSEs that were charged a Locational Reliability Charge for the day for which such Capacity Resource Deficiency Charge was assessed. Such revenues shall be distributed on a pro-rata basis to such LSEs based on their Daily Unforced Capacity Obligations.

8.4 Relief from Charges

A Capacity Market Seller or Locational UCAP Seller that is otherwise subject to the Capacity Resource Deficiency Charge solely as a result of section 8.1(f) may receive relief from such Charge if it demonstrates that the inability to provide the level of demand response specified in its Sell Offer is due to the permanent departure (due to plant closure, efficiency gains, or similar reasons) from the Transmission System of load that was relied upon for load response in such Sell Offer; provided, however, that such seller must provide the Office of the Interconnection with all information deemed necessary by the Office of the Interconnection to assess the merits of the request for relief. Such seller shall receive no RPM Auction Credit for the amount of reduction in the committed Existing Demand Resources.

13. EMERGENCY PROCEDURE CHARGE

13.1 Application of the Emergency Procedure Charge

Following an Emergency, the compliance during the period of such Emergency with the instructions of the Office of the Interconnection of: (a) each Capacity Market Seller that committed Capacity Resources, and each Locational UCAP Seller that sold Locational UCAP, for such period; and (b) each ILR Provider responsible for ILR certified for such period, shall be evaluated as recommended by the Markets and Reliability Committee and directed by the PJM Board. If, based on such evaluation, it is determined that a Capacity Market Seller, Locational UCAP Seller, or ILR Provider refused to comply with, or otherwise failed to employ its best efforts to comply with, the instructions of the Office of the Interconnection to implement PJM emergency procedures, then such Capacity Market Seller, Locational UCAP Seller, or ILR Provider shall pay an Emergency Procedure Charge.

13.2 Emergency Procedure Charge

The Emergency Procedure Charge shall equal the number of days in the Delivery Year multiplied by the Daily Deficiency Rate for such Delivery Year times each megawatt of a Demand Resource or ILR that was not implemented as directed, and each megawatt of a Generation Capacity Resource that was not made available as directed despite being capable of producing energy at the time, and that is deliverable to the PJM Region in the case of a Generation Capacity Resource located outside the PJM Region.

13.3 Allocation of Revenue from Emergency Procedure Charges

The revenue collected from assessment of an Emergency Procedure Charge shall be distributed on a pro-rata basis to all LSEs that were charged a Locational Reliability Charge for the day for which the Emergency Procedure Charge was assessed. The charges shall be allocated on a pro-rata basis to all such LSEs based on their Daily Unforced Capacity Obligation.

15. COORDINATION WITH ECONOMIC PLANNING PROCESS

Following each Base Residual Auction, the Office of the Interconnection shall review each LDA that has a Locational Price Adder to determine if Planned Generation Capacity Resources, Planned Demand Resources, or Qualifying Transmission Upgrades submitted Sell Offers that cleared in such auction. If a Locational Price Adder results from the clearing of an LDA for two consecutive Base Residual Auctions, and no such planned resources or upgrades clear in such auctions for such LDA, then the Office of the Interconnection shall evaluate in the RTEP process the costs and benefits of a transmission upgrade that would reduce to zero the Locational Price Adder for such LDA. Such evaluation will compare the cost of the upgrade over ten years against the value of elimination of the Locational Price Adder over such period. If such upgrade is found to be feasible and beneficial, it shall be included in the RTEP as soon as practicable. The annual costs of such upgrade shall be allocated ~~to all LSEs serving load in such LDA, pro rata based on such loads~~ as specified in Schedule 12 of the Tariff and Schedule 6 of the Operating Agreement.

PJM Operating Agreement
(Marked Sections / Redline Format)

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 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) In the Real-time Energy Market, Market Participants that deviate from the amounts of energy purchases or sales, or Transmission Customers that deviate from the transmission uses, scheduled in the Day-ahead Energy Market shall be obligated to purchase or sell energy, or 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.

(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 shall be conducted as specified 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.

1.10.1A Day-ahead Energy Market Scheduling.

The following actions shall occur not later than 12:00 noon 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.

(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 bilateral transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection whether the transaction is to be included in the Day-ahead Energy Market. Any Market Participant that elects to include a bilateral transaction in the Day-ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the PJM Manuals), if any, at which it will be wholly or partially curtailed rather than pay Transmission Congestion Charges. The foregoing price specification shall apply to the price difference between the specified bilateral transaction source and sink points in the day-ahead scheduling process only. Any Market Participant that elects not to include its bilateral 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 Charges in the Real-time Energy Market in order to complete any such scheduled bilateral transaction. Scheduling of bilateral transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

i) Internal Market Buyers shall submit schedules for all bilateral purchases for delivery within the PJM Region, whether from generation resources inside or outside the PJM Region;

ii) Market Sellers shall submit schedules for bilateral sales to entities outside the PJM Region from generation within the PJM Region that is not dynamically scheduled to such entities pursuant to Section 1.12; and

iii) In addition to the foregoing schedules for bilateral transactions, Market Participants shall submit confirmations of each scheduled bilateral

transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(d) Market Sellers wishing to sell into the Day-ahead Energy Market shall submit offers for the supply of energy (including energy from hydropower units), demand reductions, Regulation, Operating Reserves or other services for the following 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(d), Schedule 2 of the Operating Agreement, and the PJM Manuals, as applicable. 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 Attachment DD of the PJM Tariff, 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. The submission of offers for resource increments that have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, and the PJM Manuals, as applicable. Energy offered from generation resources that have not cleared a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff 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 Demand Resource and energy or demand reduction, amount, respectively, for each hour in the offer period, and the minimum run time for generation resources and minimum down time for Demand Resources;

ii) Shall specify the amounts and prices for the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;

iii) If based on energy from a specific generating unit, may specify start-up and no-load fees equal to the specification of such fees for such unit on file with the Office of the Interconnection, if based on reductions in demand from a Demand Resource may specify shutdown costs;

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 a second schedule 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, which offer shall remain open through the Operating Day for which the offer is submitted;

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; and

viii) Shall not exceed an energy offer price of $1,000/megawatt-hour.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation that shall specify the megawatt of Regulation being offered, which must equal or exceed 0.1 megawatts, the Regulation Zone for which such regulation is offered, the price of the offer in dollars per MWh, 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. The price of the offer shall not exceed $100 per MWh in the case of Regulation offered for all Regulation Zones. 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 heat rate increase resulting from operating the unit at lower megawatt output incurred from the provision of Regulation;

ii. The cost increase (in $/MW) in variable operating and maintenance costs resulting from operating the unit at lower megawatt output incurred from the provision of Regulation; and

iii. An adder of up to $12.00 per megawatt of Regulation provided.

Qualified Regulation capability must satisfy the 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 and no-load fees, 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.

(g) Each offer by a Market Seller of a Generation Capacity Resource shall remain in effect for subsequent Operating Days until superseded or canceled.

(h) The Office of the Interconnection shall post ~~on the PJM Open Access Same-time Information System~~ 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 Increment Bids and/or Decrement Bids that apply to the Day-ahead Energy Market only. Such bids 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 3000 bid/offer segments in the Day-ahead Energy Market, 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 Bid or Decrement Bid.

(j) A Market Seller that wishes to make a generation resource or Demand Resource available to sell Synchronized Reserve shall submit an offer for Synchronized Reserve that shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.1 megawatts, the price of the offer in dollars per megawatt hour, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the energy used by the generation resource to provide the Synchronized Reserve and the generation resource's unit specific opportunity costs. The price of the offer shall not exceed the variable operating and maintenance costs for providing Synchronized Reserve plus seven dollars and fifty cents.

(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. The offer must equal or exceed 0.1 megawatts, and the offer 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; and (iii) at the Economic Load Response Participant's option, start-up 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. 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).

(l) Market Sellers owning or controlling the output of a Demand Resource that was committed in an FRR Capacity Plan, self-supplied or offered and cleared in the Base Residual Auction or one of the Incremental Auctions, or owning or controlling the output of an ILR resource which was certified as specified in Attachment DD of the PJM Tariff, may submit demand reduction bids for the available load reduction capability of the Demand Resource or ILR resource. The submission of demand reduction bids for resource increments that have not cleared in the Base Residual Auction or in one of the Incremental Auctions, or for ILR resources that were not certified, or were not committed in an FRR Capacity Plan, shall be optional, but any such bids must contain the information specified in the PJM Economic Load Response Program to be included in such bids. A Demand Resource that was committed in an FRR Capacity Plan, self-supplied or offered and cleared in a Base Residual Auction or an 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 Demand Resources and ILR 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) Market Sellers that wish to make Day-ahead Scheduling Reserves Resources available to sell Day-ahead Scheduling Reserves shall submit offers, each of which must equal or exceed 0.1 megawatts, in the Day-ahead Scheduling Reserves Market specifying: 1) the price of the offer in dollars per megawatt hour; and 2) such other information specified by the Office of the Interconnection as may be necessary to determine any relevant opportunity costs for the resource(s). The foregoing notwithstanding, to qualify to submit offers pursuant to this section, the Day-ahead Scheduling Reserves Resources shall submit energy offers in the Day-ahead Energy Market including start-up and shut-down costs for generation resource and Demand Resources, respectively, and all generation resources that are capable of providing Day-ahead Scheduling Reserves that a particular resource can provide that service. The MW quantity of Day-ahead Scheduling Reserves that a particular resource can provide in a given hour will be determined based on the energy offer data submitted in the Day-ahead Energy Market, as detailed in the PJM Manuals.

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 Sections 1.10.9 or 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, start-up, no-load 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.

(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 and no-load fees, from the Office of the Interconnection on behalf of the Market Buyers in accordance with Section 3 of this Schedule 1. Alternatively, the Market Seller shall receive, in lieu of start-up and no-load fees, its actual costs incurred, if any, up to a cap of the resource's start-up cost, 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 offer must equal or exceed 0.1 megawatts, in minimum increments of .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 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, or otherwise not following the dispatch orders of 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.

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.

(c) A resource that has been self-scheduled shall not receive payments or credits for start-up or no-load fees.

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 dispatch 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. ~~If a Market Seller submits more than one offer on an aggregated resource basis, the withdrawal of any such offer shall be deemed a withdrawal of all higher priced offers for the same period.~~

(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 dispatch by the Office of the Interconnection shall be delivered on a block loaded basis to the ~~load~~ 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) ~~or credited~~ at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing ~~load~~ 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.

1.10.6A Transmission Loading Relief Customers.

(a) An entity that desires to elect to pay Transmission Congestion Charges in order to continue its energy schedules during an Operating Day over contract paths outside the PJM Region in the event that PJM initiates Transmission Loading Relief that otherwise would cause PJM to request security coordinators to curtail such Member's energy schedules shall:

(i) enter its election on OASIS by 12:00 p.m. of the day before the Operating Day, in accordance with procedures established by PJM, which election shall be applicable for the entire Operating Day; and

(ii) if PJM initiates Transmission Loading Relief, provide to PJM, at such time and in accordance with procedures established by PJM, the hourly integrated energy schedules that impacted the PJM Region (as indicated from the NERC Interchange Distribution Calculator) during the Transmission Loading Relief.

(b) If an entity has made the election specified in Section (a), then PJM shall not request security coordinators to curtail such entity's energy transactions, except as may be necessary to respond to Emergencies.

(c) In order to make elections under this Section 1.10.6A, an entity must (i) have met the creditworthiness standards established by the Office of the Interconnection or provided a letter of credit or other form of security acceptable to the Office of the Interconnection, and (ii) have executed either the Agreement, a Service Agreement under the PJM Tariff, or other agreement committing to pay all Transmission Congestion Charges incurred under this Section.

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 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; (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 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) Not earlier~~later~~ than 4:00 p.m. of the day before each Operating Day, or such other~~earlier~~ 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.

(c) Following posting of the information specified in Section 1.10.8(b), 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. ~~The Office of the Interconnection shall post on the PJM Open Access Same-time Information System at times specified in the PJM Manuals a revised forecast of the location and duration of any expected transmission congestion, and of the range of differences in Locational Marginal Prices between major subareas of the PJM Region expected to result from such transmission congestion.~~

(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 offer that set 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 offer that set the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Section 3.3A of this Schedule.

(e) If the Office of the Interconnection discovers an error in prices and/or cleared quantities in the Day-ahead Energy Market, Real-time Energy Market, Ancillary Services Markets or Day Ahead Scheduling Reserve Market after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants of the error 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 Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the second business day following the initial publication of the results for the Day-ahead Scheduling Reserve Market and Day-ahead Energy Market. 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, together with all available supporting documentation, by no later than 5:00 p.m. of the fifth business day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the fifth business day following the initial publication of the results in the Day-ahead Scheduling

Reserve Market and the Day-ahead Energy Market. 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 Ancillary Services Markets, Day-ahead Energy Market and Real-time Energy Market, and no later than 5:00 p.m. of the tenth calendar day following the initial publication of the results in the Day-ahead Scheduling Reserve Market. 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 Section 18.17.1 of the PJM Operating Agreement, 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, a generation rebidding period shall exist from 4:00 p.m. to 6:00 p.m. on the day before each Operating Day. During the rebidding period, Market Participants may submit revisions to generation Offer Data for any generation resource that was not selected as a pool-scheduled resource in the Day-ahead Energy Market. Adjustments to Day-ahead Energy Markets 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 10:00 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 60 minutes prior to the hour in which the adjustment is to take effect, as follows:

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 fee.

(c) With respect to a pool-scheduled resource that is included in the Day-ahead Energy Market, a Market Seller may not change or otherwise modify its offer to sell energy.

(d) 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 60 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.

(e) 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.

1.11 Dispatch.

The following procedures and principles shall govern the dispatch of the resources available to the Office of the Interconnection.

1.11.1 Resource Output.

The Office of the Interconnection shall have the authority to direct any Market Seller to adjust the output of any pool-scheduled resource increment within the operating characteristics specified in the Market Seller's offer. The Office of the Interconnection may cancel its selection of, or otherwise release, pool-scheduled resources, subject to an obligation to pay any applicable start-up, no-load or cancellation fees. The Office of the Interconnection shall adjust the output of pool-scheduled resource increments as necessary: (a) to maintain reliability, and subject to that constraint, to minimize the cost of supplying the energy, reserves, and other services required by the Market Buyers and the operation of the PJM Region; (b) to balance load and generation, maintain scheduled tie flows, and provide frequency support within the PJM Region; and (c) to minimize unscheduled interchange not frequency related between the PJM Region and other Control Areas.

1.11.2 Operating Basis.

In carrying out the foregoing objectives, the Office of the Interconnection shall conduct the operation of the PJM Region in accordance with the PJM Manuals, and shall: (i) utilize available generating reserves and obtain required replacements; and (ii) monitor the availability of adequate reserves.

1.11.3 Pool-dispatched Resources.

(a) The Office of the Interconnection shall implement the dispatch of energy from pool-scheduled resources with limited energy by direct request. In implementing mandatory or economic use of limited energy resources, the Office of the Interconnection shall use its best efforts to select the most economic hours of operation for limited energy resources, in order to make optimal use of such resources consistent with the dynamic load-following requirements of the PJM Region and the availability of other resources to the Office of the Interconnection.

(b) The Office of the Interconnection shall implement the dispatch of energy from other pool-dispatched resource increments, including generation increments from Capacity Resources the remaining increments of which are self-scheduled, by sending appropriate signals and instructions to the entity controlling such resources, in accordance with the PJM Manuals. Each Market Seller shall ensure that the entity controlling a pool-dispatched resource offered or made available by that Market Seller complies with the energy dispatch signals and instructions transmitted by the Office of the Interconnection.

1.11.3A Maximum Generation Emergency.

If the Office of the Interconnection declares a Maximum Generation Emergency, all deliveries to load that is served by Point-to-Point Transmission Service outside the PJM Region from Generation Capacity Resources committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative may be interrupted in order to serve load in the PJM Region.

1.11.4 Regulation.

(a) A Market Buyer may satisfy its Regulation Obligation from its own generation resources and/or Demand Resources capable of performing Regulation service, by contractual arrangements with other Market Participants able to provide Regulation service, or by purchases from the PJM Interchange Energy Market at the rates set forth in Section 3.2.2. PJMSettlement shall be the Counterparty to the purchases and sales of Regulation service in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Regulation Obligation.

(b) The Office of the Interconnection shall obtain Regulation service from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Demand Resources as needed to meet Regulation Zone requirements not otherwise satisfied by the Market Buyers. Generation resources or Demand Resources offering to sell Regulation shall be selected to provide Regulation on the basis of each generation resource's and Demand Resource's regulation offer and the estimated opportunity cost of a resource providing regulation and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Regulation, and other ancillary services. Estimated opportunity costs for generation resources shall be determined by the Office of the Interconnection on the basis of the expected value of the energy sales that would be foregone or uneconomic energy that would be produced by the resource in order to provide Regulation, in accordance with procedures specified in the PJM Manuals. Estimated opportunity costs for Demand Resources will be zero. ~~If the Office of the Interconnection is not able to distinguish resources offering Regulation on the basis of their regulation offers and estimated opportunity costs, resources shall be selected on the basis of the quality of Regulation provided by the resource as determined by tests administered by the Office of the Interconnection.~~

(c) The Office of the Interconnection shall dispatch resources for Regulation by sending Regulation signals and instructions to generation resources and/or Demand Resources from which Regulation service has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall comply with Regulation dispatch signals and instructions transmitted by the Office of the Interconnection and, in the event of conflict, Regulation dispatch signals and instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their resources supplying load in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4A Synchronized Reserve.

(a) A Market Buyer may satisfy its Synchronized Reserve Obligation from its own generation resources and/or Demand Resources capable of providing Synchronized Reserve, by contractual arrangements with other Market Participants able to provide Synchronized Reserve, or by purchases from the PJM Synchronized Reserve Market at the rates set forth in Section 3.2.3A. PJMSettlement shall be the Counterparty to the purchases and sales of Synchronized Reserve in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Synchronized Reserve Obligation.

(b) The Office of the Interconnection shall obtain Synchronized Reserve from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Demand Resources as needed to meet the Synchronized Reserve requirements of each Synchronized Reserve Zone of the PJM Region not otherwise satisfied by the Market Buyers. Resources offering to sell Synchronized Reserve shall be selected to provide Synchronized Reserve on the basis of each generation resource's and/or Demand Resource's Synchronized Reserve offer and the estimated unit specific opportunity cost of the resource providing Synchronized Reserve, and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Synchronized Reserve and other ancillary services. Estimated unit specific opportunity costs for generation resources shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the generation resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to 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, times (B) the absolute value of 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 Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources will be zero.

(c) The Office of the Interconnection shall dispatch generation resources and/or Demand Resources for Synchronized Reserve by sending Synchronized Reserve instructions to generation resources and/or Demand Resources from which Synchronized Reserve has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall comply with Synchronized Reserve dispatch instructions transmitted by the Office of the Interconnection and, in the event of a conflict, Synchronized Reserve dispatch instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their generation resources supplying load in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.5 PJM Open Access Same-time Information System.

The Office of the Interconnection shall update the information posted on the PJM Open Access Same-time Information System to reflect its dispatch of generation resources.

3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

(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 Section 2 of this Schedule.

(b) Market Buyers shall be charged for all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(c) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(d) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the total amount of net hourly PJM Interchange for each Market Buyer, including Generating Market Buyers, in accordance with the PJM Manuals. For Internal Market Buyers that are Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall include determination of the net energy flows from: (i) tie lines; (ii) any generation resource the output of which is controlled by the Market Buyer but delivered to it over another entity's Transmission Facilities; (iii) any generation resource the output of which is controlled by another entity but which is directly interconnected with the Market Buyer's transmission system; (iv) deliveries pursuant to bilateral energy sales; (v) receipts pursuant to bilateral energy purchases; and (vi) an adjustment to account for the day-ahead PJM Interchange, calculated as the difference between scheduled withdrawals and injections by that Market Buyer in the Day-ahead Energy Market. For External Market Buyers and Internal Market Buyers that are not Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall determine the energy scheduled hourly for delivery to the Market Buyer net of the amounts scheduled by such ~~the External~~ Market Buyer in the Day-ahead Energy Market.

(e) An Internal Market Buyer shall be charged for Spot Market Energy purchases to the extent of its hourly net purchases from the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. An External Market Buyer shall be charged for its Spot Market Energy purchases based on the energy delivered to it, determined as specified in Section 3.2.1(d) above. The total charge shall be determined by the product of the hourly net amount of PJM Interchange Imports times the hourly Real-time System Energy Price for that Market Buyer.

(f) A Generating Market Buyer shall be paid as a Market Seller for sales of Spot Market Energy to the extent of its hourly net sales into the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. The total payment shall be determined by the product of the hourly net amount of PJM Interchange Exports times the hourly Real-time System Energy Price for that Market Seller.

3.2.2 Regulation.

(a) Each Internal Market Buyer 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 requirements of such Regulation Zone for the hour, based on the Market Buyer'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"). An Internal Market Buyer that does not meet its hourly Regulation obligation shall be charged for Regulation dispatched by the Office of the Interconnection to meet such obligation at the Regulation market-clearing price determined in accordance with subsection (c) of this Section, plus the amounts, if any, described in subsection (f) of this section.

(b) A Generating Market Buyer supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection in excess of its hourly Regulation obligation shall be credited for each increment of such Regulation at the higher of (i) the Regulation market-clearing price in such Regulation Zone or (ii) the sum of the regulation offer and the unit-specific opportunity cost of the generation resource supplying the increment of Regulation, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Regulation market-clearing price in each Regulation Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day. The market-clearing price for each regulating hour shall be equal to the highest sum of a resource's Regulation offer plus its estimated unit-specific opportunity costs, determined as described in subsection (d) below from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.3.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation market-clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour shall be equal to the sum of the unit-specific opportunity costs (i) incurred during the hour in which the obligation is fulfilled, plus costs (ii) associated with uneconomic operation during the hour preceding the initial regulating hour ("preceding shoulder hour"), plus costs (iii) associated with uneconomic operation during the hour after the final regulating hour ("following shoulder hour").

The unit-specific opportunity costs incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour 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 hour in order to provide Regulation and the lesser of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, 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 the following shoulder hour 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 hour in order to provide Regulation and the lesser of the resource's actual or expected output in the following shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the following shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market.

Estimated opportunity costs for Demand Resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Generating Market Buyer 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 each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's Regulation signals from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the

resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour 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 hour in order to provide Regulation and the lesser of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, 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 the following shoulder hour 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 hour in order to provide Regulation and the lesser of the resource's actual or expected output in the following shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the following shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the following shoulder hour during which the deviation was incurred, 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 Internal Market Buyer 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.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal

supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to section 1.10.1A(e) of this Schedule. A Regulation supplier fails the three-pivotal supplier test in any hour 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 three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region for which the cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The 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.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the prices offered 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 Section 3.2.3A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, 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 Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load fees 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. Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. 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 from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), 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.

(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 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 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 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 in the Day-ahead Energy Market.

(d) The cost of Operating Reserves 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 (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; 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 dynamically scheduled to load outside such area pursuant to Section 1.12.

(e) 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~~, and that is not committed solely for the purpose of providing Synchronized Reserve:~~ 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 or minimum run time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or minimum run time (minimum down time for Demand 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 (minimum down time for Demand Resources) and Segment 2 will include the remainder of the contiguous hours 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.

Credits received pursuant to this section shall be equal to the positive difference between a resource's total offered price for start-up (shutdown costs for Demand Resources) and no-load fees and energy, determined on the basis of the resource's scheduled output, and the total value of the resource's energy as determined by the Real-time Energy Market and 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 Demand 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) plus the resource's opportunity cost and less any amounts credited for Synchronized Reserve in excess of the Synchronized Reserve offer plus the resource's opportunity cost and less any amounts credited for providing Reactive Services as specified in Section 3.2.3B, and less any amounts for Day-ahead Scheduling Reserve in excess of the Day-ahead Scheduling Reserve offer plus the resource's opportunity cost, shall be credited to the Market Seller.

Synchronized Reserve and Day-ahead Scheduling Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding hour(s) in which the Synchronized Reserve and Day-ahead Scheduling Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each hour ~~period~~ the unit operates in condensing and generation mode ~~for one or more contiguous hours~~.

(f) A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool scheduled (or self-scheduled, if operating according to 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 hourly integrated, 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 hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

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 hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

AG equals the actual hourly integrated output of the unit;

URTLMP equals the real time LMP at the unit's bus;

UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was

operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UB shall not be negative.

(f-1) A Market Seller's combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost 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 above for a steam unit or combined cycle unit operating in combined cycle mode.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG}, or (ii) {(URTLMP – UB) x DAG} where:

URTLMP equals the real time LMP at the unit's bus;

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit, determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

(f-2) A Market Seller's hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to 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~~A~~(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.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with 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, less any payments received from another Control Area for Operating Reserves, plus any redispatch costs incurred in accordance with section 10(a) of this Schedule, shall be 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 shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (i) load deviations (net of operating Behind The Meter Generation) from the Day-ahead Energy Market in megawatt-hours during that Operating Day; (ii) generation deviations (not including deviations in Behind The Meter Generation) from the Day-ahead Energy Market for non-dispatchable generation resources, including External Resources, in megawatt-hours during the Operating Day; (iii) deviations from the Day-ahead Energy Market for bilateral transactions from outside the PJM Region for delivery within such region in megawatt-hours during the Operating Day, except as noted below and in the PJM Manuals; and (iv) deviations of energy sales from the Day-ahead Energy Market 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 dynamically scheduled to load outside such region pursuant to Section 1.12.

Deviations that occur within a single Zone shall be associated with the Eastern or Western Region, as defined in Section 3.2.3(q) of this Schedule, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with Section 3.2.3(q). Deviations at interfaces and hubs shall be associated with the Eastern or Western Region if all the busses that define all interfaces or all hubs are located in the region. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to 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 busses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed 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 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 an Operating Reserve shortage in real-time or where PJM initiates the request for load reductions in real-time in order to avoid an Operating Reserve shortage as described in this Schedule, Section 6A, Scarcity Pricing.

(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.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized 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 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 for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for ~~each Control Zone of~~ the PJM Region ~~based on the Control Zone to which the resource was synchronized to provide synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation~~.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized 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 (net of operating Behind The Meter Generation, but not to be less than zero) 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 dynamically scheduled to load outside

~~such Control Zone~~ the PJM Region pursuant to 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 credit otherwise provided by Section 3.2.3.(b) or Section 3.2.3(e) in connection with marked-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 Schedule 2 of the Operating Agreement, 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 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 Section 1.9.7(b); provided, however, that the Market Seller must return to compliance with 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, the Market Seller shall not receive any credit for Operating Reserves. 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 for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatt hours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours 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 hours 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 12:00 noon 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 not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon 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 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 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 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 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 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 generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described in the PJM Manuals. Ramp-limited desired MW values shall be used to determine generation resource real-time deviations from the resource's day-ahead schedules.

The Office of the Interconnection shall calculate a ramp-limited desired MW value for 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:

$$\mathbf{Ramp\_Request}_t = \frac{(\mathbf{UDStarget}_{t-1} - \mathbf{AOutput}_{t-1})}{(\mathbf{UDSLAtime}_{t-1})}$$

$$\mathbf{RL\_Desired}_t = \mathbf{AOutput}_{t-1} + \left(\mathbf{Ramp\_Request}_t * \mathbf{Case\_Eff\_time}_{t-1}\right)$$

where:

1. UDStarget = UDS basepoint for the previous UDS case
2. AOutput = Unit's output at case solution time
3. UDSLAtime = UDS look ahead time
4. Case_Eff_time = Time between base point changes
5. RL_Desired = Ramp-limited desired MW

To determine if a 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 UDS Basepoint or the actual output and ramp-limited desired MW value. The % off dispatch and MW off dispatch will be a time-weighted average over the course of an hour. If the UDS Basepoint and the ramp-limited desired MW for the resource are unavailable, the Office of Interconnection will determine the unit's MWoff dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the UDS LMP Desired MW.

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 UDS Basepoint, or if its % off dispatch is <= 10, or it's hourly integrated Real-time MWh is within 5% or 5 MW (whichever is greater) of the hourly integrated 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 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: hourly integrated Real-time 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: hourly integrated Real-time MWh – UDS LMP Desired MW.

- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – hourly integrated 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 UDS LMP Desired MWh for the hour 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: hourly integrated Real time MWh – UDS 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:

hourly integrated Real-time Mwh – hourly integrated Ramp-Limited Desired MW. If deviation value is within 5% or 5 MW (whichever is greater) 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: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch, and the resource has tripped, for the hour the resource tripped and the hours it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time 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: hourly integrated Real-time MWh and Day-Ahead MWh.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve 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 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 Operating Reserve charges shall be allocated to real-time deviations 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 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 Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing 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 Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed 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 charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category 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(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) 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 Region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, *DEOK* transmission Zones, and the Eastern 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:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve 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 reliability 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 Section 3.2.3(p).

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of

Schedule 1 of this Agreement. 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 Section 3.2.3(p).

(iii) Reliability and deviation regional balancing Operating Reserve rates shall be determined by summing the relevant RTO balancing Operating Reserve 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.

3.2.3A Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Synchronized Reserve Zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Synchronized Reserve 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). An Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts if any, described in subsections (g), (h) and (i) of this section.

(b) A Generating Market Buyer supplying Synchronized Reserve at the direction of the Office of the Interconnection, in excess of its hourly Synchronized Reserve Obligation, shall be credited as follows:

i) Credits for Synchronized Reserve provided by generation units that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event ("Tier 1 Synchronized Reserve") shall be at the Synchronized Energy Premium Price.

ii) Credits for Synchronized Reserve provided by generation resources that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the Interconnection energy dispatch signals and instructions ("Tier 2 Synchronized Reserve") shall be the higher of (i) the Synchronized Reserve Market Clearing Price or (ii) the sum of (A) the Synchronized Reserve offer, and (B) the specific 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.

iii) Credits for Synchronized Reserve provided by Demand Resources that are synchronized to the grid and accept the obligation to reduce load in response to a Synchronized Reserve Event initiated by the Office of the Interconnection shall be the sum of (i) the higher of (A) the synchronized Reserve offer or (B) the Synchronized Reserve Market Clearing Price and (ii) if a Synchronized Reserve Event is actually initiated by the Office of the Interconnection and the Demand Resource reduced its load in response to the event, the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

(c) The Synchronized Reserve Energy Premium Price is the average of the five-minute Locational Marginal Prices calculated during the Synchronized Reserve Event plus an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Synchronized Reserve Zone by the Office of the Interconnection prior to the operating hour and such market-clearing price shall be equal to, from among the generation resources or Demand Resources selected to provide Synchronized Reserve for such Synchronized Reserve Zone, the highest sum of either (i) a generation resource's Synchronized Reserve offer and opportunity cost or (ii) a demand response resource's Synchronized Reserve offer.

(e) In determining the Synchronized Reserve Market Clearing Price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the expected Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) ~~the absolute value~~ of the difference between the expected 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 Synchronized Reserve set 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. The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the resource to provide Synchronized

Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to 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, times (B) ~~the absolute value~~ of 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 Synchronized Reserve set point for the generation 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. The opportunity costs for a Demand Resource shall be zero.

(g) Charges for Tier 1 Synchronized Reserve will be allocated in proportion to the amount of Tier 1 Synchronized Reserve applied to each Synchronized Reserve Obligation. In the event Tier 1 Synchronized Reserve is provided by a Market Seller in excess of that Market Seller's Synchronized Reserve Obligation, the remainder of the Tier 1 Synchronized Reserve that is not utilized to fulfill the Seller's obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

(h) Any amounts credited for Tier 2 Synchronized Reserve in an hour in excess of the Synchronized Reserve Market Clearing Price in that hour shall be allocated and charged to each Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation in proportion to its purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) In the event the Office of the Interconnection needs to assign more Tier 2 Synchronized Reserve during an hour than was estimated as needed at the time the Synchronized Reserve Market Clearing Price was calculated for that hour due to a reduction in available Tier 1 Synchronized Reserve, the costs of the excess Tier 2 Synchronized Reserve shall be allocated and charged to those providers of Tier 1 Synchronized Reserve whose available Tier 1 Synchronized Reserve was reduced from the needed amount estimated during the Synchronized Reserve Market Clearing Price calculation, in proportion to the amount of the reduction in Tier 1 Synchronized Reserve availability.

(j) In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled by the owner to provide Tier 2 Synchronized Reserve fails to provide the assigned or self-scheduled amount of Synchronized Reserve in response to an actual Synchronized Reserve Event, the owner of the resource shall incur an additional Synchronized Reserve Obligation in the amount of the shortfall for a period of three consecutive days with the same peak classification (on-peak or off-peak) as the day of the Synchronized Reserve Event at least three business days following the Synchronized Reserve Event. The overall Synchronized Reserve requirement for each Synchronized Reserve Zone of the PJM Region on which the Synchronized Reserve Obligations, except for the additional obligations set forth in this section, are based shall be reduced by the amount of this shortfall for the applicable three-day period.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l), is the difference between the generation resource's output or the Demand Resource's consumption at the start of the event and its output or consumption ten minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand 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 a Demand Resource will be reduced by the amount the megawatt consumption of the Demand 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 Demand 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 Demand Resource's consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Demand 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.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJMSettlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

(b) A Day-ahead Scheduling Reserves Resource that receives a Day-ahead Scheduling Reserves schedule pursuant to subsection (a) of this section shall be paid the hourly Day-ahead Scheduling Reserves Market clearing price for the MW obligation in each hour of the schedule, subject to meeting the requirements of subsection (c) of this section.

(c) To be eligible for payment pursuant to subsection (b) of this section, Day-ahead Scheduling Reserves Resources shall comply with the following provisions:

(i) Generation resources with a start time greater than thirty minutes are required to be synchronized and operating at the direction of the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule and shall have a dispatchable range equal to or greater than the Day-ahead Scheduling Reserves schedule.

(ii) Generation resources and Demand Resources with start times or shut-down times, respectively, equal to or less than 30 minutes are required to respond to dispatch directives from the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule. To meet this requirement the resource shall be required to start or shut down within the specified notification time plus its start or shut down time, provided that such time shall be less than thirty minutes.

(iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). 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 one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand 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 time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand 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 credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

Resources that do not comply with the provisions of this subsection (c) shall not be eligible to receive credits pursuant to subsection (b) of this section.

(d) The cost of credits allocated to Day-ahead Scheduling Reserves Resources pursuant to this section shall be charged to Load-Serving Entities in the PJM Region based on load ratio share (net of operating Behind The Meter Generation, but not to be less than zero), provided that a Load-Serving Entity may satisfy its Day-ahead Scheduling Reserves obligation, which is equal to the Day-ahead Scheduling Reserves Requirement multiplied by the Load-Serving Entity's load ratio share for the PJM Region, through one or any combination of the following: 1) the Day-ahead Scheduling Reserves Market; 2) and bilateral arrangements. The Day-ahead Scheduling Reserve charges allocated pursuant to this section shall reflect any portion of a Load-Serving Entity's Day-ahead Scheduling Reserves obligation that is met by bilateral arrangement(s).

(e) If the Day-ahead Scheduling Reserves Requirement is not satisfied through the operation of subsection (a) of this section, any additional Operating Reserves required to meet the requirement shall be scheduled by the Office of the Interconnection pursuant to Section 3.2.3 of Schedule 1 of this Agreement.

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 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 either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, 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 hourly in an amount equal to {(LMPDMW - AG) x (URTLMP - UB)}

where:

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 hourly integrated real time LMP;

AG equals the actual hourly integrated output of the unit;

URTLMP equals the real time LMP at the unit's bus;

UB equals the unit offer for that unit for which output is reduced or suspended determined according to the real time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UB shall not be negative.

(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 Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost 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 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.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG, or (ii) {(URTLMP – UB) x DAG where:

URTLMP equals the real time LMP at the unit's bus;

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

(e) At the end of each Operating Day, where the active energy 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).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is 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 hourly in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual hourly integrated output of the unit;

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 hourly integrated real time LMP at the unit's bus and adjusted for any regulation or Tier 2 Synchronized Reserve assignments;

UB equals the unit offer for that unit for which output is increased, determined according to the real time scheduled offer curve on which the unit was operating;

URTLMP equals the real time LMP at the unit's bus; and

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to 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~~A~~(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, 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 lost 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 lost opportunity cost compensation, the Office of Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost 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 generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 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 hourly Synchronized Reserve Market Clearing Price for each hour 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 generating unit's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generation unit's bus, (C) the generation unit's startup-cost of providing synchronous condensing, and (D) 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 to provide Reactive Services 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 (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 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. 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 (net of operating Behind The Meter Generation) 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 PJM 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 Tier 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 hourly Synchronized Reserve Market Clearing Price for each hour 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 generation resource's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) 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 (net of operating Behind The Meter Generation) 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 Section 5 of this Schedule.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Section 5 of this Schedule.

3.2.6 Emergency Energy.

(a) 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 hour of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange 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.

(b) 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 hour of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net PJM Interchange 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.

(c) The net costs or net revenues associated with sales or purchases of hourly energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each hour 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 PJM Interchange 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 Buyer in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market Buyer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Buyer's internal accounting.

(b) If deliveries to a Market Buyer that has PJM Interchange meters in accordance with Section 14 of the Operating Agreement include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market Buyer, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market Buyer and the unmetered Market Participant specified by them to the Office of the Interconnection.

3.3 Market Sellers.

Except as provided in the following sentence, the accounting and billing principles and procedures applicable to Generating Market Buyers functioning as Market Sellers shall be as set forth in Section 3.2. This Section sets forth the accounting and billing principles and procedures applicable to all other Market Sellers, and to Generating Market Buyers functioning as Market Sellers with respect to any matters not specified in Section 3.2.

3.3.1 Spot Market Energy Charges.

(a) Market Sellers shall be paid for all energy scheduled to be delivered in the Day-ahead Energy Market at the Day-ahead System Energy Prices.

(b) At the end of each hour during an Operating Day, the Office of the Interconnection shall determine the total net amount of energy delivered in the hour to the PJM Region by each of the Market Seller's resources, in accordance with the PJM Manuals and the calculation described in Section 3.2.1(f).

(c) The Office of the Interconnection shall calculate Day-ahead and Real-time System Energy Prices for the PJM Region, in accordance with Section 2 of this Schedule.

(d) A Market Seller shall be paid for real-time sales of Spot Market Energy to the extent of its hourly net deliveries to the PJM Region of energy in excess of amounts scheduled in the Day-ahead Energy Market from the Market Seller's resources. For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the hourly amounts delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region. The total real-time generation revenues for each Market Seller shall be the sum of its payments determined by the product of (i) the hourly net amount of energy delivered to the PJM Region in excess of the amount scheduled to be delivered in that hour ~~at that bus~~ in the Day-ahead Energy Market from each of the Market Seller's resources, times (ii) the hourly Real-time System Energy Price. To the extent that the energy actually injected in any hour is less than the energy scheduled to be injected ~~at that bus~~ in the Day-ahead Energy Market, the Market Seller shall be debited for the difference at the Real-time System Energy Price at the time of the shortfall times the amount of the shortfall. The total generation revenue for each Market Seller shall be the sum of the revenues at Day-ahead System Energy Prices determined in accordance with the Day-ahead Energy Market as specified in Section 3.3.1(a) plus the revenues at Real-time System Energy Prices determined as specified herein, net of any debits specified herein for each Market Seller.

3.3.2 Regulation.

Each Market Seller that is also an Internal Market Buyer as to load in a Regulation Zone shall have an hourly Regulation objective and shall be credited or charged in connection therewith as specified in Section 3.2.2. All other Market Sellers supplying Regulation in such Regulation Zone at the direction of the Office of the Interconnection shall be credited for each increment of

such Regulation at the price specified in Section 3.2.2(b), as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

3.3.3 Operating Reserves.

A Market Seller shall be credited for its pool-scheduled resources based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource, in accordance with the procedures set forth in Section 3.2.3.

3.3.4 Emergency Energy.

The net costs or net revenues associated with purchases or sales of energy in connection with Emergencies in the PJM Region, or in another Control Area, shall be allocated to Market Participants in accordance with the procedures set forth in Section 3.2.6.

3.3.5 Synchronized Reserve.

Each Market Seller that is also an Internal Market Buyer shall have an hourly Synchronized Reserve objective and shall be credited or charged in connection therewith as specified in Section 3.2.3A(a). All other Market Sellers supplying Synchronized Reserve at the direction of the Office of the Interconnection shall be credited for each increment of such Synchronized Reserve at the price specified in Section 3.2.3A(b), as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

3.3.6 Billing.

PJMSettlement shall prepare a billing statement each billing cycle for each Market Seller in accordance with the charges and credits specified in Sections 3.3.1 through 3.3.5 of this Schedule, and showing the net amount to be paid or received by the Market Seller. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Seller's internal accounting.

5.1 Transmission Congestion Charge Calculation.

5.1.1 Calculation by Office of the Interconnection.

When the transmission system is operating under constrained conditions, or as necessary to provide third-party transmission provider losses ~~in accordance with Section 9.3~~, the Office of the Interconnection shall calculate Transmission Congestion Charges for each Network Service User, Market Participants in the PJM Interchange Energy Market, and each Transmission Customer.

5.1.2 General.

The Office of the Interconnection shall calculate Congestion Prices in the form of Day-ahead Congestion Prices and Real-time Congestion Prices for the PJM Region, in accordance with Section 2 of this Schedule.

5.1.3 Network Service User Calculation.

(a) Each Network Service User shall be charged for the increased cost of energy incurred by it during each constrained hour to deliver the output of its firm Generation Capacity Resources or other owned or contracted for resources, its firm bilateral purchases, and its non-firm bilateral purchases as to which it has elected to pay Transmission Congestion Charges. ~~The Transmission Congestion Charge for deliveries from each such source shall be the Network Service User's hourly congestion net bill.~~

(b) Market Buyers shall be charged for transmission congestion resulting from all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant load bus.

(c) Generating Market Buyers shall be reimbursed for transmission congestion resulting from all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant generation bus.

(d) Market Sellers shall be reimbursed for transmission congestion resulting from all energy scheduled to be delivered in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant generation bus.

(e) The hourly net amount of energy delivered at each generation bus is determined by revenue meter data if available, or by the State Estimator, if revenue meter data is not available. The total load actually served at each load bus is initially determined by the State Estimator. For each Electric Distributor that reports hourly net energy flows from metered tie lines and for which all generators within the Electric Distributor's territory report revenue quality, hourly net energy delivered, the total revenue meter load within the Electric Distributor's territory is calculated as the sum of all net import energy flows reported by their tie revenue meters and all net generation reported via generator revenue meters. The amount of load at each of such

Electric Distributor's load buses calculated by the State Estimator is then adjusted, in proportion to its share of the total load of that Electric Distributor, in order that the total amount of load across all of the Electric Distributor's load buses matches its total revenue meter calculated load.

(f) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the Transmission Congestion Charges at each Market Buyer's load bus to be charged for congestion at Real-time Congestion Prices determined by the product of the hourly Real-time Congestion Price at the relevant bus times the Market Buyer's megawatts of load (net of operating Behind The Meter Generation, but not to be less than zero) at the bus in that hour in excess of the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the hour in the Day-ahead Energy Market. To the extent that the load (net of operating Behind The Meter Generation, but not to be less than zero) actually served at a load bus is less than the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the Day-ahead Energy Market, the Market Buyer shall be paid for the difference at the Real-time Congestion Price for the load bus at the time of the shortfall. The megawatts of load at each load bus shall be the sum of the megawatts of load (net of operating Behind The Meter Generation, but not less than zero) for that bus of that Market Buyer plus any megawatts of that Market Buyer's bilateral sales attributable to that bus. The total load charge for each Market Buyer shall be the sum, for each of a Market Buyer's load buses, of the charges at Day-ahead Congestion Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1a plus the charges at Real-time Congestion Prices determined as specified herein, net of any payments specified herein for each of the Market Buyer's load buses.

(g) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the transmission congestion payments at each Generating Market Buyer's generation bus to be paid at Real-time Congestion Prices, determined by the product of the hourly Real-time Congestion Price at the relevant bus times the Generating Market Buyer's megawatts of generation at such generation bus in the hour in excess of the energy scheduled to be injected at that bus in that hour in the Day-ahead Energy Market. To the extent that the energy actually injected at the generation bus is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Generating Market Buyer shall be debited for the difference at the Real-time Congestion Price for the generation bus at the time of the shortfall. The megawatts of generation at each generation bus shall be the sum of the megawatts of generation for that bus of that Generating Market Buyer plus any megawatts of bilateral purchases of that Generating Market Buyer attributable to that bus. The total generation revenue for each Generating Market Buyer shall be the sum, for each of the Generating Market Buyer's generation buses, of the revenues at Day-ahead Congestion Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Congestion Prices determined as specified herein, net of any debits specified herein for each of the Market Buyer's generation buses.

(h) A Market Seller shall be paid for transmission congestion that results from the Real-time sales of energy to the extent of its hourly net deliveries to the PJM Region of energy in excess of amounts scheduled in the Day-ahead Energy Market from the Market Seller's resources. For pool External Resources, the Office of the Interconnection shall model, based on an appropriate

flow analysis, the hourly amounts delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region. The total real-time generation revenues for each Market Seller shall be the sum of its credits determined by the product of (i) the hourly net amount of energy delivered to the PJM Region at the applicable generation or interface bus in excess of the amount scheduled to be delivered in that hour at that bus in the Day-ahead Energy Market from each of the Market Seller's resources, times (ii) the hourly Real-time Congestion Price at that bus. To the extent that the energy actually injected at a generation or interface bus in any hour is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Market Seller shall be debited for the difference at the Real-time Congestion Price for the applicable bus at the time of the shortfall times the amount of the shortfall. The total generation revenue for each Market Seller shall be the sum, for each of the Market Seller's generation buses or Interface Pricing Points, of the revenues at Day-ahead Congestion Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Congestion Prices determined as specified herein, net of any debits specified herein for each of the Market Seller's generation or interface buses.

5.1.4 Transmission Customer Calculation.

Each Transmission Customer using Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), each Network Customer, and each Transmission Customer using Non-Firm Point-to-Point Transmission Service (as defined in the PJM Tariff) that has elected to pay Transmission Congestion Charges, shall be charged for the increased cost of energy during constrained hours for the delivery of energy using ~~Point-to-Point~~such Transmission Service. Except as specified in this subsection, a Transmission Congestion Charge shall be assessed for transmission use scheduled in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region and the Day-ahead Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. Transmission Congestion Charges shall be assessed for real-time transmission use in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. A Transmission Customer shall be paid for Transmission Congestion Charges for real-time transmission use falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. ~~Real-time deviations from the Point-to-Point Transmission Service scheduled in the Day-ahead Energy Market shall be determined by the lesser of the real-time injection or withdrawal associated with such transmission service.~~

5.1.4A Transaction Calculation

Each Market Participant entering into transactions in the PJM Interchange Energy Markets shall be charged for the increased cost of energy during constrained hours for the delivery of energy on the scheduled path. Except as specified in this subsection, a Transmission Congestion Charge shall be assessed for cleared MWh in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Congestion Price at the sink point and the Day-ahead Congestion Price at the source point. Transmission Congestion Charges shall be assessed for real-time cleared MWh in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Congestion Price at the sink point and the Real-time Congestion Price at the source point. Such Market Participant shall be paid for Transmission Congestion Charges for real-time cleared MWh falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Congestion Price at the sink point and the Real-time Congestion Price at the source point.

5.1.5 Operating Margin Customer Calculation.

Each Control Area purchasing Operating Margin shall be assessed Transmission Congestion Charges for any increase in the cost of energy resulting from the provision of Operating Margin. The Transmission Congestion Charge shall be the amount of Operating Margin purchased in an hour multiplied by the difference in the Locational Marginal Price at what would be the delivery Interface Pricing Point and the Locational Marginal Price at what would be the source Interface Pricing Point, if the operating contingency that was the basis for the purchase of Operating Margin had occurred in that hour. Operating Margin may be allocated among multiple source and delivery Interface Pricing Points in accordance with an applicable load flow study.

5.1.6 Transmission Loading Relief Customer Calculation.

(a) Each Transmission Loading Relief Customer shall be assessed Transmission Congestion Charges for any increase in the cost of energy in the PJM Region resulting from its energy schedules over contract paths outside the PJM Region during Transmission Loading Relief.

(b) The Transmission Congestion Charge shall be the total amount of energy specified in such energy schedules multiplied by the difference between a Locational Marginal Price calculated by the Office of the Interconnection for the energy schedule source location specified in the NERC Interchange Distribution Calculator and a Locational Marginal Price calculated by the Office of the Interconnection for the energy schedule sink location specified in the NERC Interchange Distribution Calculator. Transmission Congestion Charges that are less than zero shall be set equal to zero for Transmission Loading Relief Customers.

(c) The Office of the Interconnection will determine the Locational Marginal Prices at the energy schedule source and sink locations external to PJM with reference to and based solely on the prices of energy in the PJM Region and at the Interface Pricing Points between adjacent Control Areas and the PJM Region and the system conditions and actual power flow distributions as described by the PJM State Estimator program. The Office of the Interconnection will determine the Locational Marginal Prices at the external energy schedule source and sink locations and the resulting Congestion Charge based on the portion of the energy

schedule that flows through the PJM Region as reflected by the flow distributions from the PJM State Estimator program.

5.1.7 Total Transmission Congestion Charges.

The total Transmission Congestion Charges collected by PJMSettlement each hour will be the aggregate net amounts determined as specified in ~~this Schedule~~the PJM Manuals. PJMSettlement shall collect Transmission Congestion Charges for each hour the transmission system operates under constrained conditions.

5.4 Transmission Loss Charge Calculation.

5.4.1 Calculation by Office of the Interconnection.

The Office of the Interconnection shall calculate Transmission Loss Charges for each Network Service User, Market Participant in the PJM Interchange Energy Market, and each Transmission Customer.

5.4.2 General.

(a) The basis for the Transmission Loss Charges shall be the differences in the Locational Marginal Prices, defined as the Loss Price at a bus, between points of delivery and points of receipt, as determined in accordance with Section 2 of this Schedule.

(b) The Office of the Interconnection shall calculate Loss Prices in the form of Day-ahead Loss Prices and Real-time Loss Prices for the PJM Region, in accordance with Section 2 of this Schedule.

5.4.3 Network Service User Calculation.

(a) Each Network Service User shall be charged for the increased cost of transmission losses to deliver the output of its firm Capacity Resources or other owned or contracted for resources, its firm bilateral purchases, and its non-firm bilateral purchases. ~~The Transmission Loss Charge for deliveries from each such source shall be the Network Service User's hourly losses net bill.~~

(b) Market Buyers shall be charged for transmission losses resulting from all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead Loss Price applicable to each relevant load bus.

(c) Generating Market Buyers shall be reimbursed for transmission losses resulting from all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead Loss Price applicable to each relevant generation bus.

(d) Market Sellers shall be reimbursed for transmission losses resulting from all energy scheduled to be delivered in the Day-ahead Energy Market at the Day-ahead Loss Prices applicable to each relevant generation bus.

(e) The hourly net amount of energy delivered at each generation bus is determined by revenue meter data, if available, or by the State Estimator, if revenue meter data is not available. The total load actually served at each load bus is initially determined by the State Estimator. For each Electric Distributor that reports hourly net energy flows from metered tie lines and for which all generators within the Electric Distributor's territory report revenue quality, hourly net energy delivered, the total revenue meter load within the Electric Distributor's territory is calculated as the sum of all net import energy flows reported by their tie revenue meters and all net generation reported via generator revenue meters. The amount of load at each of such

Electric Distributor's load buses calculated by the State Estimator is then adjusted, in proportion to its share of the total load of that Electric Distributor, in order that the total amount of load across all of the Electric Distributor's load buses matches its total revenue meter calculated load.

(f) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the Transmission Loss Charges at each Market Buyer's load bus to be charged for losses at Real-time Loss Prices determined by the product of the hourly Real-time Loss Prices at the relevant bus times the Market Buyer's megawatts of load (net of operating Behind The Meter Generation, but not to be less than zero) at the bus in that hour in excess of the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the hour in the Day-ahead Energy Market. To the extent that the load (net of operating Behind The Meter Generation, but not to be less than zero) actually served at a load bus is less than the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the Day-ahead Energy Market, the Market Buyer shall be paid for the difference at the Real-time Loss Price for the load bus at the time of the shortfall. The megawatts of load at each load bus shall be the sum of the megawatts of load (net of operating Behind The Meter Generation, but not less than zero) for that bus of that Market Buyer plus any megawatts of that Market Buyer's bilateral sales attributable to that bus. The total load charge for each Market Buyer shall be the sum, for each of a Market Buyer's load buses, of the charges at Day-ahead Loss Price determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1a plus the charges at Real-time Loss Prices determined as specified herein, net of any payments specified herein for each of the Market Buyer's load buses.

(g) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the transmission loss payments at each Generating Market Buyer's generation bus to be paid at Real-time Loss Prices, determined by the product of the hourly Real-time Loss Price at the relevant bus times the Generating Market Buyer's megawatts of generation at such generation bus in the hour in excess of the energy scheduled to be injected at that bus in that hour in the Day-ahead Energy Market. To the extent that the energy actually injected at the generation bus is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Generating Market Buyer shall be debited for the difference at the Real-time Loss Price for the generation bus at the time of the shortfall. The megawatts of generation at each generation bus shall be the sum of the megawatts of generation for that bus of that Generating Market Buyer plus any megawatts of bilateral purchases of that Generating Market Buyer attributable to that bus. The total generation revenue for each Generating Market Buyer shall be the sum, for each of the Generating Market Buyer's generation buses, of the revenues at Day-ahead Loss Price determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Loss Prices determined as specified herein, net of any debits specified herein for each of the Market Buyer's generation buses.

(h) A Market Seller shall be paid for transmission losses that results from the Real-time sales of Spot Market Energy to the extent of its hourly net deliveries to the PJM Region of energy in excess of amounts scheduled in the Day-ahead Energy Market from the Market Seller's resources. For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the hourly amounts delivered from each such resource to the

corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region. The total real-time generation revenues for each Market Seller shall be the sum of its credits determined by the product of (i) the hourly net amount of energy delivered to the PJM Region at the applicable generation or interface bus in excess of the amount scheduled to be delivered in that hour at that bus in the Day-ahead Energy Market from each of the Market Seller's resources, times (ii) the hourly Real-time Loss Price at that bus. To the extent that the energy actually injected at a generation bus or Interface Pricing Point in any hour is less than the energy scheduled to be injected at that bus or point in the Day-ahead Energy Market, the Market Seller shall be debited for the difference at the Real-time Loss Price for the applicable bus or point at the time of the shortfall times the amount of the shortfall. The total generation revenue for each Market Seller shall be the sum, for each of the Market Seller's generation buses or Interface Pricing Points, of the revenues at Day-ahead Loss Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Loss Prices determined as specified herein, net of any debits specified herein for each of the Market Seller's generation buses or Interface Pricing Points.

5.4.4 Transmission Customer Calculation.

Each Transmission Customer using Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), each Network Customer, and each Transmission Customer using Non-Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), shall be charged for the increased cost of transmission losses for the delivery of energy using ~~Point-to-Point~~such Transmission Service. Except as specified in this subsection, a Transmission Loss Charge shall be assessed for transmission use scheduled in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Loss Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region and the Day-ahead Loss Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. Transmission Loss Charges shall be assessed for real-time transmission use in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Loss Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Loss Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. A Transmission Customer shall be paid for Transmission Loss Charges for real-time transmission use falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Loss Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Loss Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region or the source Interface Pricing Point at the boundary of the PJM Region. ~~Real-time deviations from the Point-to-Point Transmission Service scheduled in the Day-ahead Energy Market shall be determined by the lesser of the real-time injection or withdrawal associated with such transmission service.~~

5.4.4A Transaction Calculation.

Each Market Participant entering into transactions in the PJM Interchange Energy Market shall be charged for the increased cost of transmission losses on the scheduled path. Except as

specified in this subsection, a Transmission Loss Charge shall be assessed for cleared MWh in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Loss Price at the sink point and the Day-ahead Loss Price at the source point. Transmission Loss Charges shall be assessed for real-time cleared MWh in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Loss Price at the sink point and the Real-time Loss Price at the source point. Such Market Participant shall be paid for Transmission Loss Charges for real-time cleared MWh falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Loss Price at the sink point and the Real-time Loss Price at the source point.

5.4.5 Total Transmission Loss Charges.

The total Transmission Loss Charges collected by PJMSettlement each hour will be the aggregate net amounts determined as specified in this Schedule.

6.1 Introduction.

~~Except as to the exempt generation resources identified in section 6.5 below, t~~The following procedures shall apply to any generation resource subject to the dispatch of the Office of the Interconnection that, as a result of transmission constraints, the Office of the Interconnection determines, in the exercise of Good Utility Practice, must be run in order to maintain the reliability of service in the PJM Region. The provisions of this Schedule shall otherwise apply to the scheduling, dispatch, operation and accounting treatment of such resources, to the extent not inconsistent with the provisions of this Section 6.

1.5 Procedure for Development of the Regional Transmission Expansion Plan.

1.5.1 Commencement of the Process.

(a) The Office of the Interconnection shall initiate the enhancement and expansion study process if (i) required as a result of a need for transfer capability identified by the Office of the Interconnection in its evaluation of requests for interconnection with the transmission system or for firm transmission service with a term of one year or more; (ii) required to address a need identified by the Office of the Interconnection's in its on-going evaluation of the transmission system's economic and operational adequacy and performance; (iii) required as a result of the Office of the Interconnection's assessment of the transmission system's compliance with Reliability First Corporation or SERC reliability criteria, more stringent reliability criteria, if any; or PJM operating criteria; (iv) constraints or available transfer capability shortage, including, but not limited to, available transfer capability shortages that prevent the simultaneous feasibility of stage 1A Auction Revenue Rights allocated pursuant to Section 7.4.2(b) of Schedule 1 of this Agreement, that are identified by the Office of the Interconnection as a result of generation additions or retirements, evaluation of load forecasts, congestion events on or operational performance of the transmission system, or proposals for the addition of Transmission Facilities in the PJM region; or (v) expansion of the transmission system is proposed by one or more Transmission Owners, Interconnection Customer, Network Service User or Transmission Customer, or any party that funds Network Upgrades pursuant to Section 7.8 of Schedule 1 of this Agreement..

(b) The Office of the Interconnection shall notify the Transmission Expansion Advisory Committee of the commencement of an enhancement and expansion study. The Transmission Expansion Advisory Committee shall notify the Office of the Interconnection in writing of any additional transmission considerations to be included.

1.5.2 Development of Scope, Assumptions and Procedures.

Once the need for an enhancement and expansion study has been established, the Office of the Interconnection shall consult with the Transmission Expansion Advisory Committee and the Subregional RTEP Committee, as appropriate, to prepare the study's scope, assumptions and procedures.

1.5.3 Scope of Studies.

Enhancement and expansion studies shall be completed by the Office of the Interconnection in collaboration with the affected Transmission Owners, as required. In general, enhancement and expansion studies shall include:

(a) An identification of existing and projected limitations on the transmission system's physical, economic and/or operational capability or performance, with accompanying simulations to identify the costs of controlling those limitations. Potential enhancements and expansions will be proposed to mitigate limitations controlled by non-economic means.

(b) Evaluation and analysis of potential enhancements and expansions, including alternatives thereto, needed to mitigate such limitations.

(c) Identification, evaluation and analysis of potential expansions and enhancements including, demand response programs, and other alternative technologies as appropriate to maintain system reliability.

(d) Identification, evaluation and analysis of potential enhancements and expansions for the purposes of supporting competition in the PJM region.

(e) Identification, evaluation and analysis of upgrades to support Incremental Auction Revenue Rights requested pursuant to Section 7.8 of Schedule 1 of this Agreement.

(f) Identification, evaluation and analysis of upgrades to support all transmission customers, including native load and network service customers.

(g) Engineering studies needed to determine the effectiveness and compliance of recommended enhancements and expansions, with the following PJM criteria: system reliability, operational performance, and economic efficiency.

(h) Identification, evaluation and analysis of potential enhancements and expansions designed to ensure the Transmission System's capability can support the simultaneous feasibility of all stage 1A Auction Revenue Rights allocated pursuant to Section 7.4.2(b) of Schedule 1 of this Agreement. Enhancements and expansions related to stage 1A Auction Revenue Rights identified pursuant to this section shall be recommended for inclusion in the RTEP together with a recommended in-service date based on the results of the ten (10) year stage 1A simultaneous feasibility analysis. Any such recommended enhancement or expansion under this Section 1.5.3(f) shall include, but shall not be limited to, the reason for the upgrade, the cost of the upgrade, the cost allocation identified pursuant to Section 1.5.6(g) of Schedule 6 of this Agreement and an analysis of the benefits of the enhancement or expansion, provided that any such upgrades will not be subject to a market efficiency cost/benefit analysis.

1.5.4 Supply of Data.

(a) The Transmission Owners shall provide to the Office of the Interconnection on an annual or periodic basis as specified by the Office of the Interconnection, any information and data reasonably required by the Office of the Interconnection to perform the Regional Transmission Expansion Plan, including but not limited to the following: (i) a description of the total load to be served from each substation; (ii) the amount of any interruptible loads included in the total load (including conditions under which an interruption can be implemented and any limitations on the duration and frequency of interruptions); (iii) a description of all generation resources to be located in the geographic region encompassed by the Transmission Owner's transmission facilities, including unit sizes, VAR capability, operating restrictions, and any must-run unit designations required for system reliability or contract reasons; the (iv) current Local Plan; and (v) all criteria, assumptions and models used in the current Local Plan. The data required under

this Section shall be provided in the form and manner specified by the Office of the Interconnection.

(b) In addition to the foregoing, the Transmission Owners, those entities requesting transmission service and any other entities proposing to provide Transmission Facilities to be integrated into the PJM Region shall supply any other information and data reasonably required by the Office of the Interconnection to perform the enhancement and expansion study.

(c) The Office of the Interconnection also shall solicit from the Members, Transmission Customers and other interested parties, including but not limited to electric utility regulatory agencies within the States in the PJM Region and the State Consumer Advocates, information required by, or anticipated to be useful to, the Office of the Interconnection in its preparation of the enhancement and expansion study.

(d) The Transmission Expansion Advisory Committee and the Subregional RTEP Committee shall each facilitate a minimum of one initial assumptions meeting to be scheduled at the commencement of the RTEP process. The purpose of the assumptions meeting shall be the following: (i) establish the assumptions to be used in performing the evaluation and analysis of the potential enhancements and expansions to the Transmission Facilities, (ii) incorporate regulatory initiatives as appropriate, including state regulatory agency initiated programs, (iii) provide an open forum to review the impacts of regulatory actions, projected changes in load growth, demand response resources, generating capacity, market efficiency and other trends in the industry, and (iv) provide an open forum for the review of alternative scenarios proposed by the Committee participants. The final assumptions shall be determined by the Transmission Expansion Advisory Committee for both the Regional RTEP Project and Subregional RTEP Project.

(e) After the assumptions meeting(s) the Transmission Expansion Advisory Committee and the Subregional RTEP Committee shall facilitate additional meetings and shall post all communications required to provide early opportunity for the committee participants, (as defined in Sections 1.3(b) and 1.3(c) of this Schedule 6) to review and evaluate the following: any identified violations of reliability criteria; analyses of the economic performance of the transmission system; potential transmission solutions; and the proposed RTEP. These meetings will be scheduled as deemed necessary by the Office of the Interconnection or upon the request of the Transmission Expansion Advisory Committee or the Subregional RTEP Committees. The Office of the Interconnection will provide updates on the status of the development of the RTEP at these meetings or at the regularly scheduled meetings of the PJM Planning Committee.

(f) The Office of the Interconnection shall supply any information and data reasonably required by the Members, Transmission Customers and other impacted parties, including but not limited to, electric utility regulatory agencies within the States in the PJM Region, and the State Consumer Advocates, utilized to perform the Regional Transmission Expansion Plan. Such information and data shall be provided pursuant to the appropriate protection of confidentiality provisions.

(g) The Office of the Interconnection shall provide access throught the PJM website, to the Transmission Owner's Local Plan, including all criteria, assumptions and models used by the Transmission Owners in developing their respective Local Plan ("Local Plan Information"). Local Plan Information shall be provided consistent with: (1) any applicable confidentiality provisions set forth in Section 18.17 of this Operating Agreement; (2) PJM's CEII process; and (3) any applicable copyright limitations. Notwithstanding the foregoing, PJM may share with a third party Local Plan Information that has been designated as confidential, pursuant to the provisions for such designation as set forth in Section 18.17 of this Operating Agreement and subject to: (i) agreement by the disclosing Transmission Owner consistent with the process set forth in this Operating Agreement; and (ii) an appropriate non-disclosure agreement to be executed by PJM, the Transmission Owner and the requesting third party. With the exception of confidential, CEII and copyright protected information, Local Plan Information will be provided for full review by the Planning Committee, the TEAC and the Subregional RTEP Committees.

1.5.5 Coordination of the Regional Transmission Expansion Plan.

(a) The Regional Transmission Expansion Plan shall be developed in accordance with the principles of interregional coordination with the transmission systems of the surrounding regional reliability councils and with the local transmission providers, through the Transmission Expansion Advisory Committee and the Subregional RTEP Committee.

(b) The Regional Transmission Expansion Plan shall be developed taking into account the processes for coordinated regional transmission expansion planning established under the following agreements: Joint Operating Agreement Between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C.; Northeastern ISO/RTO Planning Coordination Protocol; Joint Reliability Coordination Agreement Between the Midwest independent System Operator, Inc.; PJM Interconnection, L.L.C. and Progress Energy Carolinas. Coordinated regional transmission expansion planning shall also incorporate input from parties that may be impacted by the coordination efforts, including but not limited to, the Members, Transmission Customers, electric utility regulatory agencies in the PJM Region, and the State Consumer Advocates, in accordance with the terms and conditions of the applicable regional coordination agreements.

(c) The Regional Transmission Expansion Plan shall be developed by the Office of the Interconnection in consultation with the Transmission Expansion Advisory Committee during the enhancement and expansion study process.

(d) The Regional Transmission Expansion Plan shall be developed taking into account the processes for coordination of the Regional and subregional systems.

1.5.6 Development of the Recommended Regional Transmission Expansion Plan.

(a) The Office of the Interconnection shall be responsible for the development of the Regional Transmission Expansion Plan and for conducting the studies on which the plan is based. The Regional Transmission Expansion Plan, including the Regional RTEP Projects, the Subregional RTEP Projects and the Supplemental Projects shall be developed through an open

and collaborative process with opportunity for meaningful participation through the Transmission Expansion Advisory Committee and the Subregional RTEP Committee.

(b) Upon completion of its studies and analysis, the Office of the Interconnection shall prepare a recommended enhancement and expansion plan, which shall include alternative projects or solutions as applicable, for review by the Transmission Expansion Advisory Committee. The Transmission Expansion Advisory Committee shall facilitate open meetings and communications as necessary to provide opportunity for the Transmission Expansion Advisory Committee participants to collaborate on the preparation of the recommended enhancement and expansion plan. The Office of the Interconnection also shall invite interested parties to submit comments on the plan to the Transmission Expansion Advisory Committee and to the Office of the Interconnection.

(c) The recommended plan shall separately identify enhancements and expansions for the three PJM subregions, the PJM Mid-Atlantic Region, the PJM West Region, and the PJM South Region, and shall incorporate recommendations from the Subregional RTEP Committee.

(c.01) The recommended plan shall separately identify enhancements and expansions that are classified as Supplemental Projects.

(d) The recommended plan shall identify enhancements and expansions that relieve transmission constraints and which, in the judgment of the Office of the Interconnection, are economically justified. Such economic expansions and enhancements shall be developed in accordance with the procedures, criteria and analyses described in Section 1.5.7 below.

(e) The recommended plan shall include proposed Merchant Transmission Facilities within the PJM Region and any other enhancement or expansion of the Transmission System requested by any participant which the Office of the Interconnection finds to be compatible with the Transmission System, though not required pursuant to Section 1.1, provided that (1) the requestor has complied, to the extent applicable, with the procedures and other requirements of Part IV of the PJM Tariff; (2) the proposed enhancement or expansion is consistent with applicable reliability standards, operating criteria and the purposes and objectives of the regional planning protocol; (3) the requestor shall be responsible for all costs of such enhancement or expansion (including, but not necessarily limited to, costs of siting, designing, financing, constructing, operating and maintaining the pertinent facilities), and (4) except as otherwise provided by Part IV of the PJM Tariff with respect to Merchant Network Upgrades, the requestor shall accept responsibility for ownership, construction, operation and maintenance of the enhancement or expansion through an undertaking satisfactory to the Office of the Interconnection.

(f) For each enhancement or expansion that is included in the recommended plan, the plan shall consider, based on the planning analysis: other input from participants, including any indications of a willingness to bear cost responsibility for such enhancement or expansion; and, when applicable, relevant projects being undertaken to ensure the simultaneous feasibility of Stage 1A ARRs, to facilitate Incremental ARRs pursuant to the provisions of Section 7.8 of Schedule 1 of this Agreement or to facilitate upgrades pursuant to Parts II, III or IV of the PJM

Tariff, and designate one or more Transmission Owners or other entities to construct, own and, unless otherwise provided, finance the recommended transmission enhancement or expansion. To the extent that one or more Transmission Owners are designated to construct, own and/or finance a recommended transmission enhancement or expansion, the recommended plan shall designate the Transmission Owner that owns transmission facilities located in the Zone where the particular enhancement or expansion is to be located. Otherwise, any designation under this paragraph of more than one entity to construct, own and/or finance a recommended transmission enhancement or expansion shall also include a designation of proportional responsibility among them. Nothing herein shall prevent any Transmission Owner or other entity designated to construct, own and/or finance a recommended transmission enhancement or expansion from agreeing to undertake its responsibilities under such designation jointly with other Transmission Owners or other entities.

(g) Based on the planning analysis and other input from participants, including any indications of a willingness to bear cost responsibility for an enhancement or expansion, the recommended plan shall, for any enhancement or expansion that is included in the plan, designate (1) the Market Participant(s) in one or more Zones, or any other party that has agreed to fully fund upgrades pursuant to this Agreement or the PJM Tariff, that will bear cost responsibility for such enhancement or expansion, as and to the extent provided by any provision of the PJM Tariff or this Agreement, (2) in the event and to the extent that no provision of the PJM Tariff or this Agreement assigns cost responsibility, the Market Participant(s) in one or more Zones from which the cost of such enhancement or expansion shall be recovered through charges established pursuant to Schedule 12 of the Tariff, and (3) in the event and to the extent that the Coordinated System Plan developed under the Joint Operating Agreement Between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C. assigns cost responsibility, the Market Participant(s) in one or more Zones from which the cost of such enhancement or expansion shall be recovered. Any designation under clause (2) of the preceding sentence (A) shall further be based on the Office of the Interconnection's assessment of the contributions to the need for, and benefits expected to be derived from, the pertinent enhancement or expansion by affected Market Participants and, (B), subject to FERC review and approval, shall be incorporated in any amendment to Schedule 12 of the PJM Tariff that establishes a Transmission Enhancement Charge Rate in connection with an economic expansion or enhancement developed under Sections 1.5.6(d) and 1.5.7 of this Schedule 6 ~~and~~, (C)~~,~~ the costs associated with expansions and enhancements required to ensure the simultaneous feasibility of stage 1A Auction Revenue Rights allocated pursuant to Section 7 of Schedule 1 of this Agreement shall (1) be allocated across transmission zones based on each zone's stage 1A eligible Auction Revenue Rights flow contribution to the total stage 1A eligible Auction Revenue Rights flow on the facility that limits stage 1A ARR feasibility and (2) within each transmission zone the Network Service Users and Transmission Customers that are eligible to receive stage 1A Auction Revenue Rights shall be the Responsible Customers under Section (b) of Schedule 12 of the PJM Tariff for all expansions and enhancements included in the Regional Transmission Expansion Plan to ensure the simultaneous feasibility of stage 1A Auction Revenue Rights, and (D) the costs associated with expansions and enhancements required to reduce to zero the Locational Price Adder for LDAs as described in Section 15 of Attachment DD of OATT shall (1) be allocated across transmission zones based on each zone's pro rata

share of load in such LDA and (2) within each transmission zone, to all LSEs serving load in such LDA pro rata based on such load.

Any designation under clause (3), above, (A) shall further be based on the Office of the Interconnection's assessment of the contributions to the need for, and benefits expected to be derived from, the pertinent enhancement or expansion by affected Market Participants, and (B), subject to FERC review and approval, shall be incorporated in an amendment to a Schedule of the PJM Tariff which establishes a charge in connection with the pertinent enhancement or expansion. Before designating fewer than all customers using Point-to-Point Transmission Service or Network Integration Transmission Service within a Zone as customers from which the costs of a particular enhancement or expansion may be recovered, Transmission Provider shall consult, in a manner and to the extent that it reasonably determines to be appropriate in each such instance, with affected state utility regulatory authorities and stakeholders. When the plan designates more than one responsible Market Participant, it shall also designate the proportional responsibility among them. Notwithstanding the foregoing, with respect to any facilities that the Regional Transmission Expansion Plan designates to be owned by an entity other than a Transmission Owner, the plan shall designate that entity as responsible for the costs of such facilities.

(g.01) Certain Regional RTEP Project(s) and Subregional RTEP Project(s) may not be required for compliance with the following PJM criteria: system reliability, operational performance, or economic efficiency, pursuant to a determination by the Office of the Interconnection. These Supplemental Projects shall be separately identified in the RTEP and are not subject to approval by the PJM Board.

(h) Any Transmission Owner and other participants on the Transmission Expansion Advisory Committee may offer an alternative.

(h.01) The Office of the Interconnection shall offer an alternative for review by the Transmission Expansion Advisory Committee or the Subregional RTEP Committee when the Office of the Interconnection determines, in its sole discretion that an alternative exists.

(i) If the Office of the Interconnection adopts the alternative, based upon its review of the relative costs and benefits, the ability of the alternative to supply the required level of transmission service, and its impact on the reliability of the Transmission Facilities, the Office of the Interconnection shall make any necessary changes to the recommended plan.

(j) If, based upon its review of the relative costs and benefits, the ability of the alternative to supply the required level of transmission service, and the alternative's impact on the reliability of the Transmission Facilities, the Office of the Interconnection does not adopt an alternative proposed by a Transmission Owner or Owners, the Transmission Owner or Owners whose alternative or alternatives have not been accepted or to whom cost responsibility has been assigned and other participants on the Transmission Expansion Advisory Committee may require that its or their alternative(s) be submitted to the Dispute Resolution Procedures in Schedule 5 of the Operating Agreement.

(k) Schedule 5 of the Operating Agreement, the Dispute Resolution Procedures may be requested by the parties to a dispute arising from the Regional Transmission Expansion Plan or its development.

1.5.7 Development of Economic Transmission Enhancements and Expansions.

(a) In June of each year, concurrent with the PJM Board's consideration and approval of the reliability-based transmission enhancement and expansions to be included in the Regional Transmission Expansion Plan, the Office of the Interconnection shall obtain PJM Board approval of the assumptions to be used in performing the market efficiency analysis described in this section to identify enhancements or expansions that could relieve transmission constraints that have an economic impact ("economic constraints"). Such assumptions shall include, but not be limited to, the discount rate used to determine the present value of the Total Annual Enhancement Benefit and Total Enhancement Cost, and the annual revenue requirement, including the recovery period, used to determine the Total Enhancement Cost. The discount rate shall be based on the Transmission Owners' most recent after-tax embedded cost of capital weighted by each Transmission Owner's total transmission capitalization. Each Transmission Owner shall provide the Office of the Interconnection with the Transmission Owner's most recent after-tax embedded cost of capital, total transmission capitalization, and levelized carrying charge rate, including the recovery period. The recovery period shall be consistent with recovery periods allowed by the Commission for comparable facilities. Prior to PJM Board consideration of such assumptions, the assumptions shall be presented to the Transmission Expansion Advisory Committee for review and comment.

(b) Following PJM Board approval of the assumptions, the Office of the Interconnection shall perform a market efficiency analysis to compare the costs and benefits of (i) accelerating reliability-based enhancements or expansions already included in the Regional Transmission Plan that if accelerated also could relieve one or more economic constraints; (ii) modifying reliability–based enhancements or expansions already included in the Regional Transmission Plan that as modified would relieve one or more economic constraints; and (iii) new enhancements or expansions that could relieve one or more economic constraints, but for which no reliability-based need has been identified. Economic constraints include, but are not limited to, constraints that cause (1) significant historical gross congestion; (2) significant historical unhedgeable congestion; (3) pro-ration of Stage 1B ARR requests as described in section 7.4.2(c) of Schedule 1 of this Agreement; or (4) significant simulated congestion as forecast in the market efficiency analysis.

(c) The process for conducting the market efficiency analysis described in subsection (b) above shall include the following:

(i) The Office of the Interconnection shall identify and provide to the Transmission Expansion Advisory Committee a list of economic constraints to be evaluated in the market efficiency analysis.

(ii) The Office of the Interconnection shall identify any planned reliability-based enhancements or expansions already included in the Regional Transmission Expansion Plan,

which if accelerated would relieve such constraints, and present any such proposed reliability-based enhancements and expansions to be accelerated to the Transmission Expansion Advisory Committee for review and comment. The PJM Board, upon consideration of the advice of the Transmission Expansion Advisory Committee, thereafter shall consider and vote to approve any accelerations.

(iii) The Office of the Interconnection shall evaluate whether including any additional economic-based enhancements or expansions in the Regional Transmission Expansion Plan or modifications of existing Regional Transmission Expansion Plan reliability-based enhancements or expansions would relieve an economic constraint. In addition, any market participant at any time may submit to the Office of the Interconnection a proposal to construct an additional economic-based enhancement or expansion to relieve an economic constraint. To be considered in the market efficiency analysis commencing after approval of the Regional Transmission Expansion Plan by the PJM Board in June, market participant proposals to construct an additional economic-based enhancement or expansion must be received by the Office of the Interconnection by December 31 of the same year. Upon completion of its evaluation, including consideration of any eligible market participant proposed economic-based enhancements or expansions, the Office of the Interconnection shall present to the Transmission Expansion Advisory Committee a description of recommended new economic-based enhancements and expansions for review and comment. Upon consideration of the advice of the Transmission Expansion Advisory Committee, the PJM Board shall consider any new economic-based enhancements and expansions for inclusion in the Regional Transmission Plan and for those enhancements and expansions it approves, the PJM Board shall designate (a) the entity or entities that will be responsible for constructing and owning or financing the additional economic-based enhancements and expansions, (b) the estimated costs of such enhancements and expansions, and (c) the market participants that will bear responsibility for the costs of the additional economic-based enhancements and expansions pursuant to section 1.5.6(g) of this Schedule 6. In the event the entity or entities designated as responsible for construction, owning or financing a designated new economic-based enhancement or expansion declines to construct, own or finance the new economic-based enhancement or expansion, the enhancement or expansion will not be included in the Regional Transmission Expansion Plan but will be included in the report filed with the FERC in accordance with sections 1.6 and 1.7 of this Schedule. This report also shall include information regarding PJM Board approved accelerations of reliability-based enhancements or expansions that an entity declines to accelerate.

(d) To determine the economic benefits of accelerating or modifying planned reliability-based enhancements or expansions or of constructing additional economic based enhancements or expansions and whether such economic-based enhancements or expansion are eligible for inclusion in the Regional Transmission Expansion Plan, the Office of the Interconnection shall perform and compare market simulations with and without the proposed accelerated or modified planned reliability-based enhancements or expansions or the additional economic-based enhancements or expansions as applicable, using the Benefit/Cost Ratio calculation set forth below in this section 1.5.7(d). An economic-based enhancement or expansion shall be included in the Regional Transmission Expansion Plan recommended to the PJM Board, if the relative benefits and costs of the economic-based enhancement or expansion meet a Benefit/Cost Ratio Threshold of at least 1.25:1.

The Benefit/Cost Ratio shall be determined as follows:

Benefit/Cost Ratio = [Present value of the Total Annual Enhancement Benefit for each of the first 15 years of the life of the enhancement or expansion] ÷ [Present value of the Total Enhancement Cost for each of the first 15 years of the life of the enhancement or expansion]

Where

Total Annual Enhancement Benefit = Energy Market Benefit + Reliability Pricing Model Benefit

and

Energy Market Benefit = [.70] * [Change in Total Energy Production Cost] + [.30] * [Change in Load Energy Payment]

and

Change in Total Energy Production Cost = [the estimated total annual fuel costs, variable O&M costs, and emissions costs of the dispatched resources in the PJM Region without the economic-based enhancement or expansion] – [the estimated total annual fuel costs, variable O&M costs, and emissions costs of the dispatched resources in the PJM Region with the economic-based enhancement or expansion]

and

Change in Load Energy Payment = [the annual sum of (the hourly estimated zonal load megawatts for each Zone) * (the hourly estimated zonal Locational Marginal Price for each Zone without the economic-based enhancement or expansion)] – [the annual sum of (the hourly estimated zonal load megawatts for each Zone) * (the hourly estimated zonal Locational Marginal Price for each Zone with the economic-based enhancement or expansion)] – [the change in value of transmission rights for each Zone with the economic-based enhancement or expansion (as measured using currently allocated Auction Revenue Rights plus additional Auction Revenue Rights made available by the proposed acceleration or modification of the planned reliability-based enhancement or expansion or new economic based enhancement or expansion)]. For economic-based enhancements and expansions for which cost responsibility is assigned pursuant to section (b)(i) of Schedule 12 of the PJM Tariff, the Change in the Load Energy

Payment shall be the sum of the Change in Load Energy Payment in all Zones. For economic-based enhancements or expansions for which cost responsibility is assigned pursuant to section (b)(v) of Schedule 12 of the PJM Tariff, the Change in Load Energy Payment shall be the sum of the Change in the Load Energy Payment only of the Zones that show a decrease in Load Energy Payment.

and

Reliability Pricing Benefit = [.70] * [Change in Total System Capacity Cost] + [.30] * [Change in Load Capacity Payment]

and

Change in Total System Capacity Cost = [the sum of (the megawatts that are estimated to be cleared in the Base Residual Auction under Attachment DD of the PJM Tariff) * (the prices that are estimated to be contained in the Sell Offers for each such cleared megawatt without the economic-based enhancement or expansion) * (the number of days in the study year)] – [the sum of (the megawatts that are estimated to be cleared in the Base Residual Auction under Attachment DD of the PJM Tariff) * (the prices that are estimated to be contained in the Sell Offers for each such cleared megawatt with the economic-based enhancement or expansion) * (the number of days in the study year)]

and

Change in Load Capacity Payment = [the sum of (the estimated zonal load megawatts in each Zone) * (the estimated Final Zonal Capacity Prices under Attachment DD of the PJM Tariff without the economic-based enhancement or expansion) * (the number of days in the study year)] – [the sum of (the estimated zonal load megawatts in each Zone) * (the estimated Final Zonal Capacity Prices under Attachment DD of the PJM Tariff with the economic-based enhancement or expansion) * (the number of days in the study year)]. The Change in Load Capacity Payment shall take account of the change in value of Capacity Transfer Rights in each Zone, including any additional Capacity Transfer Rights made available by the proposed acceleration or modification of the planned reliability-based enhancement or expansion or new economic based enhancement or expansion. For economic-based enhancements and expansions for which cost responsibility is assigned pursuant to section (b)(i) of Schedule 12 of the PJM Tariff, the Change in the Load Capacity Payment shall be the sum

of the change in Load Capacity Payment in all Zones. For economic-based enhancements or expansions for which cost responsibility is assigned pursuant to section (b)(v) of Schedule 12 of the PJM Tariff, the Change in Load Capacity Payment shall be the sum of the change in the Load Capacity Payment only of the Zones that show a decrease in Load Capacity Payment.

and

Total Enhancement Cost (except for accelerations of planned reliability-based enhancements or expansions) = the estimated annual revenue requirement for the economic-based enhancement or expansion.

Total Enhancement Cost (for accelerations of planned reliability-based enhancements or expansions) = the estimated change in annual revenue requirement resulting from the acceleration of the planned reliability-based enhancement or expansion, taking account of all of the costs incurred that would not have been incurred but for the acceleration of the planned reliability-based enhancement or expansion.

(e) For informational purposes only, to assist the Office of the Interconnection and the Transmission Expansion Advisory Committee in evaluating the economic benefits of accelerating planned reliability-based enhancements or expansions or of constructing a new economic-based enhancement or expansion, the Office of the Interconnection shall calculate and post on the PJM internet site the change in the following metrics on a zonal and system-wide basis: (i) total energy production costs (fuel costs, variable O&M costs and emissions costs);(ii) total load energy payments (zonal load MW times zonal load Locational Marginal Price); (iii) total generator revenue from energy production (generator MW times generator Locational Marginal Price); (iv) Financial Transmission Right credits (as measured using currently allocated Auction Revenue Rights plus additional Auction Revenue Rights made available by the proposed acceleration or modification of a planned reliability-based enhancement or expansion or new economic based enhancement or expansion); (v) marginal loss surplus credit; and (vi) total capacity costs and load capacity payments under the Office of the Interconnection's Commission-approved capacity construct.

(f) To assure that new economic-based enhancements and expansions included in the Regional Transmission Expansion Plan continue to be cost beneficial, the Office of the Interconnection annually shall review the costs and benefits of constructing such enhancements and expansions. In the event that there are changes in these costs and benefits, the Office of the Interconnection shall review the changes in costs and benefits with the Transmission Expansion Advisory Committee and recommend to the PJM Board whether the new economic-based enhancements and expansions continue to provide measurable benefits, as determined in accordance with subsection (d), and should remain in the Regional Transmission Expansion Plan. The annual review of the costs and benefits of constructing new economic-based enhancements and expansions included in the Regional Transmission Expansion Plan shall include review of changes in cost estimates of the economic-based enhancement or expansion,

and changes in system conditions, including but not limited to, changes in load forecasts, and anticipated Merchant Transmission Facilities, generation, and demand response, consistent with the requirements of subsection (k).

(g) With respect to each new economic-based enhancement or expansion included in the Regional Transmission Expansion Plan, the Office of the Interconnection shall provide to the Transmission Expansion Advisory Committee the level and type of new generation and demand response that could eliminate the need for the enhancement or expansion.

(h) For new economic enhancements or expansions with costs in excess of $50 million, an independent review of such costs shall be performed to assure both consistency of estimating practices and that the scope of the new economic-based enhancements and expansions is consistent with the new economic-based enhancements and expansions as recommended in the market efficiency analysis.

(i) For informational purposes only, the Office of the Interconnection shall post monthly on the PJM Internet site analyses of gross and unhedgeable congestion associated with transmission constraints in the PJM Region, including the level of available economic generation used to calculate unhedgeable congestion costs.

(j) At any time, market participants may submit to the Office of the Interconnection requests to interconnect Merchant Transmission Facilities or generation facilities pursuant to Part IV of the PJM Tariff that could address an economic constraint. In the event the Office of the Interconnection determines that the interconnection of such facilities would relieve an economic constraint, the Office of the Interconnection may designate the project as a "market solution" and, in the event of such designation, sections 36A or 41A of the PJM Tariff, as applicable, shall apply to the project.

(k) The assumptions used in the market efficiency analysis described in subsection (b) and any review of costs and benefits pursuant to subsection (f) shall include, but not be limited to, the following:

(i) Timely installation of Qualifying Transmission Upgrades, as defined in section 2.5.7 of Attachment DD of the PJM Tariff, that are committed to the PJM Region as a result of any Reliability Pricing Model Auction pursuant to Attachment DD of the PJM Tariff or any FRR Capacity Plan pursuant to Schedule 8.1 of the Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region, on file with FERC as PJM Interconnection, L.L.C. Rate Schedule FERC No. 44 ("RAA").

(ii) Availability of Generation Capacity Resources, as defined by section 1.33 of the RAA, that are committed to the PJM Region as a result of any Reliability Pricing Model Auction pursuant to Attachment DD of the PJM Tariff or any FRR Capacity Plan pursuant to Schedule 8.1 of the RAA.

(iii) Availability of Demand Resources as defined in section 1.13 of the RAA that are committed to the PJM Region as a result of any Reliability Pricing Model Auction pursuant to Attachment DD of the PJM Tariff or any FRR Capacity Plan pursuant to Schedule 8.1 of the RAA.

(iv) Availability of ILR Resources certified pursuant to section 5.13 of Attachment DD of the PJM Tariff.

(v) Addition of Customer Facilities pursuant to an executed Interconnection Service Agreement or Interim Interconnection Service Agreement.

(vi) Addition of Customer-Funded Upgrades pursuant to an executed Interconnection Construction Service Agreement or an Upgrade Construction Service Agreement.

(vii) Expected level of demand response over at least the ensuing fifteen years based on analyses that consider historic levels of demand response, expected demand response growth trends, impact of capacity prices, current and emerging technologies.

(viii) Expected levels of potential new generation and generation retirements over at least the ensuing fifteen years based on analyses that consider generation trends based on existing generation on the system, generation in the PJM interconnection queues and Capacity Resource Clearing Prices under Attachment DD of the PJM Tariff. If the Office of the Interconnection finds that the PJM reserve requirement is not met in any of its future year market efficiency analyses then it will model adequate future generation based on type and location of generation in existing PJM interconnection queues.

(ix) Items (i) through (vi) will be included in the market efficiency assumptions if qualified before January 1 of the year that the assumptions are presented to the PJM Board for approval in June. In the event that any of the items listed in (i) through (vi) above qualify for inclusion in the market efficiency analysis assumptions, however, because of the timing of the qualification the item was not included in the assumptions used in developing the most recent Regional Transmission Expansion Plan, the Office of the Interconnection, to the extent necessary, shall notify any entity constructing an economic-based enhancement or expansion that may be affected by inclusion of such item in the assumptions for the next market efficiency analysis described in subsection (b) and

any review of costs and benefits pursuant to subsection (f) that the need for the economic-based enhancement or expansion may be diminished or obviated as a result of the inclusion of the qualified item in the assumptions for the next annual market efficiency analysis or review of costs and benefits.

(l) For informational purposes only, with regard to economic-based enhancements or expansions that are included in the Regional Transmission Expansion Plan pursuant to subsection (d) of this section 1.5.7, the Office of the Interconnection shall perform sensitivity analyses around key inputs, such as price forecasts and expected levels of demand response, used in the market simulations to determine the Benefit/Cost Ratio for such enhancements and expansions and shall provide the results of such sensitivity analyses to the Transmission Expansion Advisory Committee.

2. NEW PARTIES

With regard to the addition, withdrawal or removal of a party to the Reliability Assurance Agreement, the Office of the Interconnection shall:

(a) Receive and evaluate the information submitted by entities that plan to serve loads within the PJM Region, including entities whose participation in the Agreement will expand the boundaries of the PJM Region.~~,~~ ~~s~~Such evaluation shall~~to~~ be conducted in accordance with the requirements of the Reliability Assurance Agreement; and

(b) Evaluate the effects of the withdrawal or removal of a party from the Reliability Assurance Agreement.

3. IMPLEMENTATION OF RELIABILITY ASSURANCE AGREEMENT

With regard to the implementation of the provisions of the Reliability Assurance Agreement, the Office of the Interconnection shall:

(a) Receive all required data and forecasts from the parties to the Reliability Assurance Agreement and other owners or providers of Capacity Resources;

(b) Perform all calculations and analyses necessary to determine the Forecast Pool Requirement and the capacity obligations imposed under the Reliability Assurance Agreement, including periodic reviews of the capacity benefit margin for consistency with the Reliability Principles and Standards, as the foregoing terms are defined in the Reliability Assurance Agreement;

(c) Monitor the compliance of each party to the Reliability Assurance Agreement with its obligations under the Reliability Assurance Agreement;

(d) Keep cost records, and bill and collect any costs or charges due from the parties to the Reliability Assurance Agreement and distribute those charges in accordance with the terms of the Reliability Assurance Agreement;

(e) Assist with the development of rules and procedures for determining and demonstrating the capability of Capacity Resources;

(f) Establish the capability and deliverability of Generation Capacity Resources consistent with the requirements of the Reliability Assurance Agreement;

(g) Establish standards and procedures for Planned Demand Resources;

(h) Collect and maintain generator availability data;

(ih) Perform any other forecasts, studies or analyses required to administer the Reliability Assurance Agreement;

(ji) Coordinate maintenance schedules for generation resources operated as part of the PJM Region;

(kj) Determine and declare that an Emergency exists or has ceased to exist in all or any part of the PJM Region or announce that an Emergency exists or ceases to exist in a Control Area interconnected with the PJM Region;

(lk) Enter into agreements for (i) the transfer of energy in Emergencies in the PJM Region or in a Control Area interconnected with the PJM Region and (ii) mutual support in such Emergencies with other Control Areas interconnected with the PJM Region; and

(ml) Coordinate the curtailment or shedding of load, or other measures appropriate to alleviate an Emergency, to preserve reliability in accordance with FERC, NERC or Applicable Regional

Reliability Council principles, guidelines, standards and requirements and the PJM Manuals, and to ensure the operation of the PJM Region in accordance with Good Utility Practice.

PJM Reliability Assurance Agreement
(Marked Sections / Redline Format)

ARTICLE 1 -- DEFINITIONS

Unless the context otherwise specifies or requires, capitalized terms used herein shall have the respective meanings assigned herein or in the Schedules hereto for all purposes of this Agreement (such definitions to be equally applicable to both the singular and the plural forms of the terms defined). Unless otherwise specified, all references herein to Articles, Sections or Schedules, are to Articles, Sections or Schedules of this Agreement. As used in this Agreement:

1.1 Agreement

Agreement shall mean this Reliability Assurance Agreement, together with all Schedules hereto, as amended from time to time.

1.1A Annual Demand Resource

Annual Demand Resource shall mean a resource that is placed under the direction of the Office of the Interconnection during the Delivery Year, and will be available for an unlimited number of interruptions during such Delivery Year by the Office of the Interconnection, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time for the months of June through October and the following May, and 6:00AM through 9:00PM Eastern Prevailing Time for the months of November through April unless there is an Office of the Interconnection approved maintenance outage during October through April. The Annual Demand Resource must be available in the corresponding Delivery year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Annual Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

1 .2 Applicable Regional Reliability Council

Applicable Regional Reliability Council shall have the same meaning as in the PJM Tariff.

1.3 Base Residual Auction

Base Residual Auction shall have the same meaning as in Attachment DD to the PJM Tariff.

1.4 Behind The Meter Generation

Behind The Meter Generation shall mean 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 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 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.

1.5 Black Start Capability

Black Start Capability shall mean the ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the power system.

1.6 Capacity Emergency Transfer Objective ("CETO")

Capacity Emergency Transfer Objective ("CETO") shall mean the amount of electric energy that a given area must be able to import in order to remain within a loss of load expectation of one event in 25 years when the area is experiencing a localized capacity emergency, as determined in accordance with the PJM Manuals. Without limiting the foregoing, CETO shall be calculated based in part on EFORD determined in accordance with Paragraph C of Schedule 5.

1.7 Capacity Emergency Transmission Limit ("CETL")

Capacity Emergency Transmission Limit ("CETL") shall mean the capability of the transmission system to support deliveries of electric energy to a given area experiencing a localized capacity emergency as determined in accordance with the PJM Manuals.

1.8 Capacity Resources

Capacity Resources shall mean megawatts of (i) net capacity from existing or Planned Generation Capacity Resources meeting the requirements of Schedules 9 and 10 that are or will be owned by or contracted to a Party and that are or will be committed to satisfy that Party's obligations under this Agreement, or to satisfy the reliability requirements of the PJM Region, for a Delivery Year; (ii) net capacity from existing or Planned Generation Capacity Resources within the PJM Region not owned or contracted for by a Party which are accredited to the PJM Region pursuant to the procedures set forth in Schedules 9 and 10; and (iii) load reduction capability provided by Demand Resources, Energy Efficiency Resources, or ILR that are accredited to the PJM Region pursuant to the procedures set forth in Schedule 6.

1.9 Capacity Transfer Right

Capacity Transfer Right shall have the meaning specified in Attachment DD to the PJM Tariff.

1.10 Control Area

Control Area shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common generation control scheme is applied in order to:

(a) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and Applicable Regional Reliability Councils;

(d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and

(e) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.11 Daily Unforced Capacity Obligation

Daily Unforced Capacity Obligation shall have the meaning set forth in Schedule 8 or, as to an FRR Entity, in Schedule 8.1.

1.12 Delivery Year

Delivery Year shall mean a Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Attachment DD to the Tariff or pursuant to an FRR Capacity Plan.

1.13 Demand Resource

Demand Resource or "DR" shall mean a Limited Demand Resource, Extended Summer Demand Resource, or Annual Demand Resource with a demonstrated capability to provide a reduction in demand or otherwise control load in accordance with the requirements of Schedule 6 that offers and that clears load reduction capability in a Base Residual Auction or Incremental Auction or that is committed through an FRR Capacity Plan. As set forth in Schedule 6, a Limited Demand Resource, Extended Summer Demand Resource or Annual Demand Resource may be an existing demand response resource or a Planned Demand Resource.

1.14 Demand Resource Provider

Demand Resource Provider shall have the meaning specified in Attachment DD to the PJM Tariff.

1.15 DR Factor

DR Factor shall mean that factor approved from time to time by the PJM Board used to determine the unforced capacity value of a Demand Resource or ILR in accordance with Schedule 6.

1.16 East RAA

East RAA shall mean that certain Reliability Assurance Agreement among Load-Serving Entities in the PJM Region, PJM Rate Schedule FERC No. 27.

1.17 Electric Cooperative

Electric Cooperative shall mean an entity owned in cooperative form by its customers that is engaged in the generation, transmission, and/or distribution of electric energy.

1.18 Electric Distributor

Electric Distributor shall mean an entity that owns or leases with rights equivalent to ownership electric distribution facilities that are providing electric distribution service to electric load within the PJM Region.

1.19 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.

1.20 End-Use Customer

End-Use Customer shall mean a Member that is a retail end-user of electricity within the PJM Region.

1.20A Energy Efficiency Resource

Energy Efficiency Resource shall mean a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of Schedule 6 of this Agreement and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak periods as described in Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

1.20B Existing Generation Capacity Resource

Existing Generation Capacity Resource shall mean, for purposes of the must-offer requirement and mitigation of offers for any RPM Auction for a Delivery Year, a Generation Capacity Resource that, as of the date on which bidding commences for such auction: (a) is in service; or (b) is not yet in service, but has cleared any RPM Auction for any prior Delivery Year. Notwithstanding the foregoing, a Generation Capacity Resource for which construction has not commenced and which would otherwise have been treated as a Planned Generation Capacity Resource but for the fact that it was bid into RPM Auctions for at least two consecutive Delivery Years, and cleared the last such auction only because it was considered existing and its mitigated offer cap was accepted when its price offer would not have otherwise been accepted, shall be deemed to be a Planned Generation Capacity Resource. A Generation Capacity Resource shall be deemed to be in service if interconnection service has ever commenced (for resources located in the PJM Region), or if it is physically and electrically interconnected to an external Control Area and is in full commercial operation (for resources not located in the PJM Region). The additional megawatts of a Generation Capacity Resource that is being, or has been, modified to increase the number of megawatts of available installed capacity thereof shall not be deemed to be an Existing Generation Capacity Resource until such time as those megawatts (a) are in service; or (b) are not yet in service, but have cleared any RPM Auction for any prior Delivery Year.

1.20C Extended Summer Demand Resource

Extended Summer Demand Resource shall mean a resource that is placed under the direction of the Office of the Interconnection and that will be available June through October and the following May, and will be available for an unlimited number of interruptions during such months by the Office of the Interconnection, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Extended Summer Demand Resource must be available June through October and the following May in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Extended Summer Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

1.21 Facilities Study Agreement

Facilities Study Agreement shall have the same meaning as in the PJM Tariff

1.22 FERC

FERC shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department.

1.23 Firm Point-To-Point Transmission Service

Firm Point-To-Point Transmission Service shall mean Firm Transmission Service provided pursuant to the rates, terms and conditions set forth in Part II of the PJM Tariff.

1.24 Firm Transmission Service

Firm Transmission Service shall mean transmission service that is intended to be available at all times to the maximum extent practicable, subject to an Emergency, an unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility or the Office of the Interconnection.

1.25 Fixed Resource Requirement Alternative or FRR Alternative

Fixed Resource Requirement Alternative or FRR Alternative shall mean an alternative method for a Party to satisfy its obligation to provide Unforced Capacity hereunder, as set forth in Schedule 8.1 to this Agreement.

1.26 Forecast Pool Requirement

Forecast Pool Requirement shall mean the amount equal to one plus the unforced reserve margin (stated as a decimal number) for the PJM Region required pursuant to this Agreement, as approved by the PJM Board pursuant to Schedule 4.1.

1.27 Forecast RTO ILR Obligation

Forecast RTO ILR Obligation shall have the same meaning as in the PJM Tariff.

1.28 Forecast Zonal ILR Obligation

Forecast Zonal ILR Obligation shall have the same meaning as in the PJM Tariff.

1.29 FRR Capacity Plan

FRR Capacity Plan shall mean a long-term plan for the commitment of Capacity Resources to satisfy the capacity obligations of a Party that has elected the FRR Alternative, as more fully set forth in Schedule 8.1 to this Agreement.

1.30 FRR Entity

FRR Entity shall mean, for the duration of such election, a Party that has elected the FRR Alternative hereunder.

1.31 FRR Service Area

FRR Service Area shall mean (a) the service territory of an IOU as recognized by state law, rule or order; (b) the service area of a Public Power Entity or Electric Cooperative as recognized by franchise or other state law, rule, or order; or (c) a separately identifiable geographic area that is: (i) bounded by wholesale metering, or similar appropriate multi-site aggregate metering, that is visible to, and regularly reported to, the Office of the Interconnection, or that is visible to, and regularly reported to an Electric Distributor and such Electric Distributor agrees to aggregate the load data from such meters for such FRR Service Area and regularly report such aggregated information, by FRR Service Area, to the Office of the Interconnection; and (ii) for which the FRR Entity has or assumes the obligation to provide capacity for all load

(including load growth) within such area ~~excluding the load of Single-Customer LSEs that are FRR Entities~~. In the event that the service obligations of an Electric Cooperative or Public Power Entity are not defined by geographic boundaries but by physical connections to a defined set of customers, the FRR Service Area in such circumstances shall be defined as all customers physically connected to transmission or distribution facilities of such Electric Cooperative or Public Power Entity within an area bounded by appropriate wholesale aggregate metering as described above.

1.32 Full Requirements Service

Full Requirements Service shall mean wholesale service to supply all of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

1.33 Generation Capacity Resource

Generation Capacity Resource shall mean a generation unit, or the right to capacity from a specified generation unit, that meets the requirements of Schedules 9 and 10 of this Agreement. A Generation Capacity Resource may be an Existing Generation Capacity Resource or a Planned Generation Capacity Resource.

1.34 Generation Owner

Generation Owner shall mean a Member that owns or leases with rights equivalent to ownership facilities for the generation of electric energy that are located within the PJM Region. Purchasing all or a portion of the output of a generation facility shall not be sufficient to qualify a Member as a Generation Owner.

1.35 Generator Forced Outage

Generator Forced Outage shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the PJM Manuals. A reduction in output or removal from service of a generating unit in response to changes in market conditions shall not constitute a Generator Forced Outage.

1.36 Generator Maintenance Outage

Generator Maintenance Outage shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform repairs on specific components of the facility, if removal of the facility qualifies as a maintenance outage pursuant to the PJM Manuals.

1.37 Generator Planned Outage

Generator Planned Outage shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the Office of the Interconnection in accordance with the PJM Manuals.

1.38 Good Utility Practice

Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the region.

1.39 ILR Provider

ILR Provider shall have the meaning specified in Attachment DD to the PJM Tariff.

1.40 Incremental Auction

Incremental Auction shall mean the First Incremental Auction, the Second Incremental Auction, the Third Incremental Auction, or the Conditional Incremental Auction, each as defined in Attachment DD to the PJM Tariff.

1.41 Interconnection Agreement

Interconnection Agreement shall have the same meaning as in the PJM Tariff.

1.42 Interruptible Load for Reliability, or ILR

Interruptible Load for Reliability, or ILR, shall mean a resource with a demonstrated capability to provide a reduction in demand or otherwise control load in accordance with the requirements of Schedule 6 that is certified by PJM no later than three months prior to a Delivery Year. At a minimum, ILR shall be available for interruption for at least 10 times during the summer period of June through September in the Delivery Year, and will be capable of maintaining each such interruption for at least a 6-hour duration. At a minimum, the ILR shall be available for such interruptions on weekdays, other than NERC holidays, from 12:00PM (noon) to 8:00PM Eastern Prevailing Time in the corresponding Delivery Year.

1.43 IOU

IOU shall mean an investor-owned utility with substantial business interest in owning and/or operating electric facilities in any two or more of the following three asset categories: generation, transmission, distribution.

1.43A Limited Demand Resource

Limited Demand Resource shall mean a resource that is placed under the direction of the Office of the Interconnection and that will, at a minimum, be available for interruption for at least 10 times during the summer period of June through September in the Delivery Year, and will be capable of maintaining each such interruption for at least a 6-hour duration. At a minimum, the Limited Demand Resource shall be available for such interruptions on weekdays, other than NERC holidays, from 12:00PM (noon) to 8:00PM Eastern Prevailing Time. The Limited Demand Resource must be available during the summer period of June through September in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as a Limited Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

1.44 Load Serving Entity or LSE

Load Serving Entity or LSE shall mean any entity (or the duly designated agent of such an entity), including a load aggregator or power marketer, (i) serving end-users within the PJM Region, and (ii) that has been granted the authority or has an obligation pursuant to state or local law, regulation or franchise to sell electric energy to end-users located within the PJM Region. Load Serving Entity shall include any end-use customer that qualifies under state rules or a utility retail tariff to manage directly its own supply of electric power and energy and use of transmission and ancillary services.

1.45 Locational Reliability Charge

Locational Reliability Charge shall mean the charge determined pursuant to Schedule 8.

1.46 Markets and Reliability Committee

Markets and Reliability Committee shall mean the committee established pursuant to the Operating Agreement as a Standing Committee of the Members Committee.

1.47 Member

Member shall mean an entity that satisfies the requirements of Sections 1.24 and 11.6 of the PJM Operating Agreement. In accordance with Article 4 of this Agreement, each Party to this Agreement also is a Member.

1.48 Members Committee

Members Committee shall mean the committee specified in Section 8 of the PJM Operating Agreement composed of the representatives of all the Members.

1.49 NERC

NERC shall mean the North American Electric Reliability Council or any successor thereto.

1.50 Network Resources

Network Resources shall have the meaning set forth in the PJM Tariff.

1.51 Network Transmission Service

Network Transmission Service shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part III of the PJM Tariff or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner (as that term is defined in the PJM Tariff).

1.52 Nominated Demand Resource Value

Nominated Demand Resource Value shall have the meaning specified in Attachment DD to the PJM Tariff.

1.53 Nominated ILR Value

Nominated ILR Value shall have the meaning specified in Attachment DD to the PJM Tariff.

1.54 Non-Retail Behind the Meter Generation

Non-Retail Behind the Meter Generation shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, and electric distribution companies to serve load.

1.55 Obligation Peak Load

Obligation Peak Load shall have the meaning specified in Schedule 8 of this Agreement.

1.56 Office of the Interconnection

Office of the Interconnection shall mean the employees and agents of PJM Interconnection, L.L.C., subject to the supervision and oversight of the PJM Board, acting pursuant to the Operating Agreement.

1.57 Operating Agreement of PJM Interconnection, L.L.C. or Operating Agreement

Operating Agreement of PJM Interconnection, L.L.C. or Operating Agreement shall mean that certain agreement, dated April 1, 1997 and as amended and restated June 2, 1997 and as amended from time to time thereafter, among the members of the PJM Interconnection, L.L.C.

1.58 Operating Reserve

Operating Reserve shall mean the amount of generating capacity scheduled to be available for a specified period of an operating day to ensure the reliable operation of the PJM Region, as specified in the PJM Manuals.

1.59 Other Supplier

Other Supplier shall mean a Member that is (i) a seller, buyer or transmitter of electric capacity or energy in, from or through the PJM Region, and (ii) is not a Generation Owner, Electric Distributor, Transmission Owner or End-Use Customer.

1.60 Partial Requirements Service

Partial Requirements Service shall mean wholesale service to supply a specified portion, but not all, of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

1.61 Percentage Internal Resources Required

Percentage Internal Resources Required shall mean, for purposes of an FRR Capacity Plan, the percentage of the LDA Reliability Requirement for an LDA that must be satisfied with Capacity Resources located in such LDA.

1.62 Party

Party shall mean an entity bound by the terms of this Agreement.

1.63 PJM

PJM shall mean the PJM Board and the Office of the Interconnection.

1.64 PJM Board

PJM Board shall mean the Board of Managers of the PJM Interconnection, L.L.C., acting pursuant to the Operating Agreement.

1.65 PJM Manuals

PJM Manuals shall mean the instructions, rules, procedures and guidelines established by the Office of the Interconnection for the operation, planning and accounting requirements of the PJM Region.

1.66 PJM Open Access Transmission Tariff or PJM Tariff

PJM Open Access Transmission Tariff or PJM Tariff shall mean the tariff for transmission service within the PJM Region, as in effect from time to time, including any schedules, appendices, or exhibits attached thereto.

1.67 PJM Region

PJM Region shall have the same meaning as provided in the Operating Agreement.

1.68 PJM Region Installed Reserve Margin

PJM Region Installed Reserve Margin shall mean the percent installed reserve margin for the PJM Region required pursuant to this Agreement, as approved by the PJM Board pursuant to Schedule 4.1.

1.69 Planned Demand Resource

Planned Demand Resource shall mean a Demand Resource that does not currently have the capability to provide a reduction in demand or to otherwise control load, but that is scheduled to be capable of providing such reduction or control on or before the start of the Delivery Year for which such resource is to be committed, as determined in accordance with the requirements of Schedule 6.

1.69A Planned External Generation Capacity Resource

Planned External Generation Capacity Resource shall mean a proposed Generation Capacity Resource, or a proposed increase in the capability of a Generation Capacity Resource, that (a) is to be located outside the PJM Region, (b) participates in the generation interconnection process of a Control Area external to PJM, (c) is scheduled to be physically and electrically interconnected to the transmission facilities of such Control Area on or before the first day of the Delivery Year for which such resource is to be committed to satisfy the reliability requirements of the PJM Region, and (d) is in full commercial operation prior to the first day of such Delivery Year, such that it is sufficient to provide the Installed Capacity set forth in the Sell Offer forming the basis of such resource's commitment to the PJM Region. Prior to participation in any Reliability Pricing Model Auction for such Delivery Year, the Capacity Market Seller must demonstrate that it has executed an interconnection agreement (functionally equivalent to a System Impact Study Agreement under the PJM Tariff for Base Residual Auction and an Interconnection Service Agreement under the PJM Tariff for Incremental Auction) with the transmission owner to whose transmission facilities or distribution facilities the resource is being directly connected, and if applicable the transmission provider. A Planned External Generation Capacity Resource must provide evidence to PJM that it has been studied as a Network Resource, or such other similar interconnection product in such external Control Area, must provide contractual evidence that it has applied for or purchased transmission service to be deliverable to the PJM border, and must provide contractual evidence that it has applied for transmission service to be deliverable to the bus at which energy is to delivered, the agreements for which must have been executed prior to participation in any Reliability Pricing Model Auction for such Delivery Year. An External Generation Capacity Resource shall cease to be considered a Planned External Generation Capacity Resource as of the earlier of (i) the date that interconnection service commences as to such resource; or (ii) the resource has cleared an RPM Auction, in which case it shall become an Existing Generation Capacity Resource for purposes of the mitigation of offers for any RPM Auction for all subsequent Delivery Years.

1.70 Planned Generation Capacity Resource

Planned Generation Capacity Resource shall mean a Generation Capacity Resource participating in the generation interconnection process under Part IV, Subpart A of the PJM Tariff, for which: (i) Interconnection Service is scheduled to commence on or before the first day of the Delivery Year for which such resource is to be committed to RPM or to an FRR Plan; (ii) a System Impact Study Agreement has been executed prior to the Base Residual Auction for such Delivery Year; (iii) an Interconnection Service Agreement has been executed prior to any Incremental Auction for such Delivery Year in which such resource plans to participate; and (iv) no megawatts of capacity have cleared an RPM Auction for any prior Delivery Year. For purposes of the must-offer requirement and mitigation of offers for any RPM Auction for a Delivery Year, a Generation Capacity Resource shall cease to be considered a Planned Generation Capacity Resource as of the earlier of (i) the date that Interconnection Service commences as to such resource; or (ii) the resource has cleared an RPM Auction for any Delivery Year, in which case it shall become an Existing Generation Capacity Resource for any RPM Auction for all subsequent Delivery Years. Notwithstanding the foregoing, a Generation Capacity Resource for which construction has not commenced and which would otherwise have been treated as a Planned Generation Capacity Resource but for the fact that it was bid into RPM Auctions for at least two consecutive Delivery Years, and cleared the last such auction only because it was considered existing and its mitigated offer cap was accepted when its price offer would not have otherwise been accepted, shall be deemed to be a Planned Generation Capacity Resource.

1.71 Planning Period

Planning Period shall mean the 12 months beginning June 1 and extending through May 31 of the following year, or such other period approved by the Members Committee.

1.72 Public Power Entity

Public Power Entity shall mean any agency, authority, or instrumentality of a state or of a political subdivision of a state, or any corporation wholly owned by any one or more of the foregoing, that is engaged in the generation, transmission, and/or distribution of electric energy.

1.73 Qualifying Transmission Upgrades

Qualifying Transmission Upgrades shall have the meaning specified in Attachment DD to the PJM Tariff.

1.74 ~~Markets and Reliability Committee~~ [Reserved for Future Use]

~~Markets and Reliability Committee shall mean the committee established pursuant to the Operating Agreement as a Standing Committee of the Members Committee.~~

1.75 Reliability Principles and Standards

Reliability Principles and Standards shall mean the principles and standards established by NERC or an Applicable Regional Reliability Council to define, among other things, an acceptable probability of loss of load due to inadequate generation or transmission capability, as amended from time to time.

1.76 Required Approvals

Required Approvals shall mean all of the approvals required for this Agreement to be modified or to be terminated, in whole or in part, including the acceptance for filing by FERC and every other regulatory authority with jurisdiction over all or any part of this Agreement.

1.77 Self-Supply

Self Supply shall have the meaning provided in Attachment DD to the PJM Tariff.

1.78 ~~Single Customer LSE~~[Reserved for Future Use]

~~Single Customer LSE shall mean a Party that (a) serves only retail customers that are Affiliates of such Party; (b) owns or controls generation facilities located at one or more of the retail customer location(s) that in the aggregate satisfy at least 50% of such Party's Unforced Capacity obligations; and (c) serves retail customers having (i) an Obligation Peak Load at all locations of no less than 100 MW, where such peak load of each such location is no less than 10 MW; or (ii) an Obligation Peak Load at each location served of no less than 25 MW.~~

1.79 South RAA

South RAA shall mean that certain Reliability Assurance Agreement among Load-Serving Entities in the PJM South Region, on file with FERC as PJM Rate Schedule FERC No. 40.

1.80 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.

1.81 State Regulatory Structural Change

State Regulatory Structural Change shall mean as to any Party, a state law, rule, or order that, after September 30, 2006, initiates a program that allows retail electric consumers served by such Party to choose from among alternative suppliers on a competitive basis, terminates such a program, expands such a program to include classes of customers or localities served by such Party that were not previously permitted to participate in such a program, or that modifies retail electric market structure or market design rules in a manner that materially increases the likelihood that a substantial proportion of the customers of such Party that are eligible for retail choice under such a program (a) that have not exercised such choice will exercise such choice; or

(b) that have exercised such choice will no longer exercise such choice, including for example, without limitation, mandating divestiture of utility-owned generation or structural changes to such Party's default service rules that materially affect whether retail choice is economically viable.

1.82 Threshold Quantity

Threshold Quantity shall mean, as to any FRR Entity for any Delivery Year, the sum of (a) the Unforced Capacity equivalent (determined using the Pool-Wide Average EFORD) of the Installed Reserve Margin for such Delivery Year multiplied by the Preliminary Forecast Peak Load for which such FRR Entity is responsible under its FRR Capacity Plan for such Delivery Year, plus (b) the lesser of (i) 3% of the Unforced Capacity amount determined in (a) above or (ii) 450 MW. If the FRR Entity is not responsible for all load within a Zone, the Preliminary Forecast Peak Load for such entity shall be the FRR Entity's Obligation Peak Load last determined prior to the Base Residual Auction for such Delivery Year, times the Base FRR Scaling Factor (as determined in accordance with Schedule 8.1).

1.83 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.

1.84 Transmission Owner

Transmission Owner shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

1.85 Transmission Owners Agreement

Transmission Owners Agreement shall mean that certain Consolidated Transmission Owners Agreement, dated as of December 15, 2005 and as amended from time to time, among transmission owners within the PJM Region.

1.86 Unforced Capacity

Unforced Capacity shall mean installed capacity rated at summer conditions that is not on average experiencing a forced outage or forced derating, calculated for each Capacity Resource on the 12-month period from October to September without regard to the ownership of or the contractual rights to the capacity of the unit.

1.87 West RAA

West RAA shall mean the "PJM West Reliability Assurance Agreement among the Load Serving Entities in the PJM West Region," on file with FERC as PJM Rate Schedule FERC No. 32.

1.88 Zonal Capacity Price

Zonal Capacity Price shall mean the price of Unforced Capacity in a Zone that an LSE that has not elected the FRR Alternative is obligated to pay for a Delivery Year as determined pursuant to Attachment DD to the PJM Tariff.

1.89 Zone

Zone shall mean an area within the PJM Region, as set forth in Schedule 15, or as such areas may be (i) combined as a result of mergers or acquisitions or (ii) added as a result of the expansion of the boundaries of the PJM Region. A Zone shall include any Non-Zone Network Load (as defined in the PJM Tariff) located outside the PJM Region that is served from such Zone under Schedule H-A of the PJM Tariff.

ARTICLE 2 -- PURPOSE

This Agreement is intended to ensure that adequate Capacity Resources, including planned and ~~e~~Existing Generation Capacity Resources, planned and existing Demand Resources, Energy Efficiency Resources, and ILR will be planned and made available to provide reliable service to loads within the PJM Region, to assist other Parties during Emergencies and to coordinate planning of such resources consistent with the Reliability Principles and Standards. Further, it is the intention and objective of the Parties to implement this Agreement in a manner consistent with the development of a robust competitive marketplace. To accomplish these objectives, this Agreement is among all of the Load Serving Entities within the PJM Region. Unless this Agreement is terminated as provided in Section 3.3, every entity which is or will become a Load Serving Entity within the PJM Region is to become and remain a Party to this Agreement or to an agreement (such as a requirements supply agreement) with a Party pursuant to which that Party has agreed to act as the agent for the Load Serving Entity for purposes of satisfying the obligations under this Agreement related to the load within the PJM Region of that Load Serving Entity. Nothing herein is intended to abridge, alter or otherwise affect the emergency powers the Office of the Interconnection may exercise under the Operating Agreement and PJM Tariff.

5.2 Breach by a Party.

The provisions of Section 15.1 of the Operating Agreement shall apply to ~~If~~ a Party's (a) failure~~s~~ to pay any amount due under this Agreement ~~within 30 days after the~~when due ~~date~~ or (b) ~~is in~~ breach of any material obligation under this Agreement~~, the Office of the Interconnection shall cause a notice of such non-payment or breach to be sent to that Party~~. In addition to the remedies available to the Office of the Interconnection set forth in Section 15.1 of the Operating Agreement, ~~I~~if the Party fails~~, within 3 days of the receipt of such notice (except as otherwise described below),~~ to cure such non-payment or breach, ~~or if the breach cannot be cured within such time and if the Party does not diligently commence to cure the breach within such time and to diligently pursue such cure to completion,~~ the Office of the Interconnection and the remaining Parties may, without an election of remedies, exercise all remedies available at law or in equity or other appropriate proceedings. Such proceedings may include (a~~c~~) the commencement of a proceeding before the appropriate state regulatory commission(s) to request suspension or revocation of the breaching Party's license or authorization to serve retail load within the state(s) and/or (~~d~~b) bringing any civil action or actions or recovery of damages that may include, but not be limited to, all amounts due and unpaid by the breaching Party, and all costs and expenses reasonably incurred in the exercise of its remedies hereunder (including, but not limited to, reasonable attorneys' fees).

8.1 Nature of Charges.

Upon the advice and recommendations of the Members Committee, the PJM Board shall, subject to any Required Approvals, approve certain charges to be imposed on a Party for its failure to satisfy its obligations under this Agreement, as set forth in this Agreement~~Schedule 12~~.

8.2 Determination of Charge Amounts.

No later than April 1 of each year, the Members Committee shall recommend to the PJM Board such charges to be applicable under this Agreement during the following Planning Period ~~and Schedule 12~~, which, upon approval by the PJM Board, shall be modified accordingly, subject to the receipt of all Required Approvals. The Markets and Reliability Committee may establish projected charges for estimating purposes only.

9.1 Overall Coordination.

Each Party shall cooperate with the other Parties in the coordinated planning and operation of their owned or contracted for Capacity Resources to obtain a degree of reliability consistent with the Reliability Principles and Standards. In furtherance of such cooperation each Party shall:

(a) ~~coordinate its Capacity Resource plans with the other Parties to maintain reliable service to its own electric customers and those of the other Parties;~~

~~(b)~~ cooperate with the members and associate members of such Party's Applicable Regional Reliability Council to ensure the reliability of the region;

(~~c~~b) make available its Capacity Resources to the other Parties through the Office of the Interconnection for coordinated operation and to supply the needs of the PJM Region for Operating Reserves;

(~~d~~c) provide or arrange for Network Transmission Service or Firm Point-to-Point Transmission Service for service to the projected load of the Party and include all Capacity Resources as Network Resources designated pursuant to the PJM Tariff or Points of Receipt for Firm Point-to-Point Transmission Service;

(~~e~~d) provide or arrange for sufficient reactive capability and voltage control facilities to meet Good Utility Practice and to be consistent with the Reliability Principles and Standards;

(~~f~~e) implement emergency procedures and take such other coordination actions as may be necessary in accordance with the directions of the Office of the Interconnection in times of Emergencies; and

(~~g~~f) maintain or arrange for Black Start Capability for a portion of its Capacity Resources at least equal to that established from time-to-time by the Office of the Interconnection.

9.3 Data Submissions.

Each Party shall submit to the Office of the Interconnection the data and other information necessary for the performance of this Agreement as may be more fully described, ~~including its plans for the addition, modification and removal of Capacity Resources, its load forecasts, and such other data set forth~~ in Schedule 11 hereof.

9.4 Charges for Failures to Comply.

(a) An emergency procedure charge, as set forth in Attachment DD to the PJM Tariff, shall be imposed on any Party that fails to comply with the directions of the Office of the Interconnection in times of Emergencies.~~pursuant to Section 9.1(f)~~

(b) A data submission charge, as set forth in Schedule 12, shall be imposed on any Party that fails to submit the data, plans or other information required by this Agreement in a timely or accurate manner as provided in Schedule 11.

SCHEDULE 7

PLANS TO MEET OBLIGATIONS

A. Each Party that elects to meet its estimated obligations for a Delivery Year by Self-Supply of Capacity Resources shall notify~~submit to~~ the Office of the Interconnection via the Internet site designated by the Office of the Interconnection, ~~no later than one month~~ prior to the start of the Base Residual Auction for such Delivery Year~~, its plans for such Capacity Resources, including (1) installation of Generation Capacity Resources (2) purchases, and (3) installation of Demand Resources, Energy Efficiency measures, or ILR~~.

B. ~~The Capacity Resource plans of each Party shall indicate the nature and current status of each resource, including the status of a Planned Generation Capacity Resource or Planned Demand Resource, the potential for deactivation or retirement of a Generation Capacity Resource or Demand Resource, and the status of commitments for each sale or purchase of capacity included in its plans. The Office of the Interconnection will review the adequacy of the submittals hereunder both as to timing and content.~~

~~C.~~ A Party that Self-Supplies Capacity Resources to satisfy its obligations for a Delivery Year must submit a Sell Offer as to such resource in the Base Residual Auction for such Delivery Year, in accordance with Attachment DD to the PJM Tariff.

~~D~~C. If, at any time after the close of the Third Incremental Auction for a Delivery Year, including at any time during such Delivery Year, a Capacity Resource that a Party has committed as a Self-Supplied Capacity Resource becomes physically incapable of delivering capacity or reducing load, the Party may submit a replacement Capacity Resource to the Office of the Interconnection. Such replacement Capacity Resource (1) may not be previously committed for such Delivery Year, (2) shall be capable of providing the same quantity of megawatts of capacity or load reduction as the originally committed Capacity Resource, and (3) shall meet the same locational requirements, if applicable, as the originally committed resource. In accordance with Attachment DD to the PJM Tariff, the Office of the Interconnection shall determine the acceptability of the replacement Capacity Resource.

B. Eligibility

1. ~~Except as provided in subsection B.3 below, a~~A Party is eligible to select the FRR Alternative if it (a) is an IOU, Electric Cooperative, or Public Power Entity; and (b) demonstrates the capability to satisfy the Unforced Capacity obligation for all load in an FRR Service Area, including all expected load growth in such area, for the term of such Party's participation in the FRR Alternative.

2. A Party eligible under B.1 above may select the FRR Alternative only as to all of its load in the PJM Region; provided however, that a Party may select the FRR Alternative for only part of its load in the PJM Region if (a) the Party elects the FRR Alternative for all load (including all expected load growth) in one or more FRR Service Areas; (b) the Party complies with the rules and procedures of the Office of the Interconnection and all relevant Electric Distributors related to the metering and reporting of load data and settlement of accounts for separate FRR Service Areas; and (c) the Party separately allocates its Capacity Resources to and among FRR Service Areas in accordance with rules specified in the PJM Manuals.

~~3. Single Customer LSEs as identified in accordance with subsection B.3.a below shall be eligible to elect the FRR Alternative upon the terms and conditions of this Schedule and the following additional terms and conditions. The aggregate Obligation Peak Load of all Single Customer LSEs electing the FRR Alternative in the PJM Region shall not exceed 1000 MW.~~

~~a) Single Customer LSEs eligible for the FRR Alternative shall be limited to those that elected the FRR Alternative on or before April 1, 2008. The Office of the Interconnection, as necessary, shall establish and post in the PJM Manuals open season procedures to apportion the maximum allowed service under the FRR Alternative among interested Single Customer LSEs.~~

~~b) The Single Customer LSE must install and maintain wholesale metering at each location that is monitored by, and regularly reported to, the Office of the Interconnection.~~

~~c) Each Single Customer LSE warrants that (i) it has and shall maintain and enforce the contract right during the term of its election of the FRR Alternative to prohibit its retail customer(s) from terminating service from the Single Customer LSE and obtaining such service from a different LSE; and (ii) it has and shall maintain for such term Financial Security or a Corporate Guaranty, both as defined in Attachment Q to the PJM Tariff, in an amount sufficient to cover any charge assessed under subsection B.3.e. A Single Customer LSE will not violate its requirement under this subsection in the event that the retail customer terminates its service from the Single Customer LSE and obtains service from an LSE that is an FRR Entity, provided that the Single Customer LSE assigns Capacity Resources to the LSE providing such service in an amount equal to the Daily Unforced Capacity Obligation related to such retail customer.~~

~~d) Each Single Customer LSE shall obtain from its retail customer(s) and provide to the Office of the Interconnection and the entity designated under state law, order, or rule as such customer's default service provider or provider of last resort and the Electric~~

Distributor a written statement agreeing that in the event such customer terminates its service from the Single-Customer LSE and obtains such service from a Party that is not an FRR Entity, then such customer's load shall be treated as ILR for the remaining duration of the period for which such Single-Customer LSE had elected the FRR Alternative, that for such purpose the Electric Distributor is authorized to obtain certification of such load as ILR, and that the customer agrees to provide the Electric Distributor with all information required for such certification. Nothing in this provision shall preclude such customer from using its owned or controlled generation to facilitate the interruption of its load as ILR.

e) A Single-Customer LSE shall be assessed an Unauthorized Load Transfer Charge in the event such LSEs retail customer terminates its service from such LSE and obtains service from a Party that has not elected the FRR Alternative, or in the event such load transfer occurs to a Party that has elected the FRR Alternative, but the Single-Customer LSE does not transfer sufficient Capacity Resources as required by subsection B.3.c. Such charge shall equal two times the Cost of New Entry times the Daily Unforced Capacity Obligation related to such customer for the remaining duration of the period for which such Single-Customer LSE elected the FRR Alternative.

f) Each Single-Customer LSE shall provide to the Office of the Interconnection an FRR Capacity Plan in accordance with this schedule. Such FRR Capacity Plan, in addition to complying with all other applicable requirements of this Schedule, shall identify and commit for at least five delivery years Capacity Resources sufficient to satisfy such LSEs Daily Unforced Capacity Obligations hereunder consisting of generation assets or physical supply contracts that qualify as a 'forward contract' or a 'commodity contract' under the U.S. Bankruptcy Code. Each Single-Customer LSE warrants that all generation assets and forward supply contracts included in its FRR Capacity Plan shall be assigned to any successor-in-interest of its retail customer(s)'s assets and operations.

E. Conditions on Purchases and Sales of Capacity Resources by FRR Entities

1. An FRR Entity may not include in its FRR Capacity Plan for any Delivery Year any Capacity Resource that has cleared in any auction under Attachment DD of the PJM Tariff for such Delivery Year. Nothing herein shall preclude an FRR Entity from including in its FRR Capacity Plan any Capacity Resource that has not cleared such an auction for such Delivery Year. Furthermore, nothing herein shall preclude an FRR Entity from including in its FRR Capacity Plan a Capacity Resource obtained from a different FRR Entity, provided, however, that each FRR Entity shall be individually responsible for meeting its capacity obligations hereunder, and provided further that the same megawatts of Unforced Capacity shall not be committed to more than one FRR Capacity Plan for any given Delivery Year.

2. An FRR Entity that designates Capacity Resources in its FRR Capacity Plan(s) for a Delivery Year based on the Threshold Quantity may offer to sell Capacity Resources in excess of that needed for the Threshold Quantity in any auction conducted under Attachment DD of the PJM Tariff for such Delivery Year, but may not offer to sell Capacity Resources in the auctions for any such Delivery Year in excess of an amount equal to the lesser of (a) 25% times the Unforced Capacity equivalent of the Installed Reserve Margin for such Delivery Year multiplied by the Preliminary Forecast Peak Load for which such FRR Entity is responsible under its FRR Capacity Plan(s) for such Delivery Year, or (b) 1300 MW.

3. An FRR Entity that designates Capacity Resources in its FRR Capacity Plan(s) for a Delivery Year based on the Threshold Quantity may not offer to sell such resources in any Reliability Pricing Model auction, ~~but,~~ but may use such resources to meet any increased capacity obligation resulting from unanticipated growth of the loads in its FRR Capacity Plan(s), or may sell such resources to serve loads located outside the PJM Region, or to another FRR Entity, subject to subsection E.1 above.

4. A Party that has selected the FRR Alternative for only part of its load in the PJM Region pursuant to Section B.2 of this Schedule that designates Capacity Resources as Self-Supply in a Reliability Pricing Model Auction to meet such Party's expected Daily Unforced Capacity Obligation under Schedule 8 shall not be required, solely as a result of such designation, to identify Capacity Resources in its FRR Capacity Plan(s) based on the Threshold Quantity; provided, however, that such Party may not so designate Capacity Resources in an amount in excess of the lesser of (a) 25% times such Party's total expected Unforced Capacity obligation (under both Schedule 8 and Schedule 8.1), or (b) 200 MW. A Party that wishes to avoid the foregoing limitation must identify Capacity Resources in its FRR Capacity Plan(s) based on the Threshold Quantity.

G. Capacity Resource Performance

Any Capacity Resource committed by an FRR Entity in an FRR Capacity Plan for a Delivery Year shall be subject during such Delivery Year to the charges set forth in sections 7, 9, 10, 11, and 13 of Attachment DD to the PJM Tariff; provided, however, the Daily Deficiency Rate under sections 7, 9, and 13 thereof shall be 1.20 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions), and the charge rates under section 10 thereof, shall be the Capacity Resource Clearing Price resulting from the RPM Auctions for the Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged as described above. An FRR Entity shall have the same opportunities to cure deficiencies and avoid or reduce associated charges during the Delivery Year that a Market Seller has under Sections 7, 9, and 10 of Attachment DD to the PJM Tariff. An FRR Entity may cure deficiencies and avoid or reduce associated charges prior to the Delivery Year by procuring replacement Unforced Capacity outside of any RPM ~~a~~Auction and committing such capacity in its FRR Capacity Plan.

SCHEDULE 10.1

LOCATIONAL DELIVERABILITY AREAS AND REQUIREMENTS

The capacity obligations imposed under this Agreement recognize the locational value of Capacity Resources. To ensure that such locational value is properly recognized and quantified, the Office of the Interconnection shall follow the procedures in this Schedule.

A. ~~Following the Transition Period, as such term is defined in Attachment DD to the Tariff, t~~The Locational Deliverability Areas for the purposes of determining locational capacity obligations hereunder, but not necessarily for the purposes of the Regional Transmission Expansion Planning Protocol, shall consist of the following Zones (as defined in Schedule 15), combinations of such Zones, and portions of such Zones:

- ATSI
- *DEOK*
- Dominion
- Penelec
- ComEd
- AEP
- Dayton
- Duquesne
- APS
- AE
- BGE
- DPL
- PECO
- PEPCO
- PSEG
- JCPL
- MetEd
- PPL
- Mid-Atlantic Area Council (MAAC) Region (consisting of all the zones listed below for Eastern MAAC, Western MAAC, and Southwestern MAAC)
- ComEd, AEP, Dayton, APS, Duquesne, ATSI, *and DEOK*
- Eastern MAAC (PSE&G, JCP&L, PECO, AE, DPL & RE)
- Southwestern MAAC (PEPCO & BG&E)
- Western MAAC (Penelec, MetEd, PPL)
- PSEG northern region (north of Linden substation); and
- DPL southern region (south of Chesapeake and Delaware Canal

The Locational Deliverability Areas for the purposes of determining locational capacity obligations hereunder, but not necessarily for the purposes for the Regional Transmission Expansion Planning Protocol, shall also include any new Zones expected to be integrated into

PJM prior to the commencement of the Base Residual Auction for the Delivery Year for which the locational capacity obligation is being determined.

B. For purposes of evaluating the need for any changes to the foregoing list, Locational Deliverability Areas shall be those areas, identified by the load deliverability analyses conducted pursuant to the Regional Transmission Expansion Planning Protocol and the PJM Manuals that have a limited ability to import capacity due to physical limitations of the transmission system, voltage limitations or stability limitations. Such limits on import capability shall not reflect the effect of Qualifying Transmission Upgrades offered in the Base Residual Auction. The Locational Deliverability Areas identified in Paragraph A above (as it may be amended from time to time) for a Delivery Year shall be modeled in the Base Residual Auction and any Incremental Auction conducted for such Delivery Year. If the Office of the Interconnection includes a new Locational Deliverability Area in the Regional Transmission Expansion Planning Protocol, it shall make a filing with FERC to amend this Schedule to add a new Locational Deliverability Area (including a new aggregate LDA), if such new Locational Deliverability Area is projected to have a capacity emergency transfer limit less than 1.15 times the capacity emergency transfer objective of such area, or if warranted by other reliability concerns consistent with the Reliability Principles and Standards. In addition, any Party may propose, and the Office of the Interconnection shall evaluate, consistent with the same CETO/CETO comparison or other reliability concerns, possible new Locational Deliverability Areas (including aggregate LDAs) for inclusion under the Regional Transmission Expansion Planning Protocol and for purposes of determining locational capacity obligations hereunder.

C. For each Locational Deliverability Area for which a separate VRR Curve was established for a Delivery Year, the Office of the Interconnection shall determine, pursuant to procedures set forth in the PJM Manuals, the Percentage of Internal Resources Required, that must be committed during such Delivery Year from Capacity Resources physically located in such Locational Deliverability Area.

SCHEDULE 11

DATA SUBMITTALS

To perform the studies required to determine the Forecast Pool Requirement and Daily Unforced Capacity Obligations under this Agreement and to determine compliance with the obligations imposed by this Agreement, each Party and other owner of a Capacity Resource shall submit data to the Office of the Interconnection in conformance with the following minimum requirements:

1. All data submitted shall satisfy the requirements, as they may change from time to time, of any procedures adopted by the Members Committee.

2. Data shall be submitted in an electronic format, or as otherwise specified by the Markets and Reliability Committee and approved by the PJM Board.

3. Actual outage data for each month for Generator Forced Outages, Generator Maintenance Outages and Generator Planned Outages shall be submitted so that it is received by such date specified in the PJM Manuals.

4. On or before the date specified in the PJM Manuals, planned and maintenance outage data for all Generation Resources ~~and load forecasts (including seasonal and average weekly peaks)~~ shall be submitted.

~~5. On or before the date specified in the PJM Manuals, adjustments to forecasts shall be submitted.~~

~~6. On or before the date or schedule for updates specified in the PJM Manuals, revisions to capacity and load forecasts (including the plans for satisfying the Daily Unforced Capacity Obligation of the Party) shall be submitted.~~

~~7. Capacity plans or revisions to previously submitted capacity plans, required under Schedule 6.~~

~~8. As desired by a Party, revisions to monthly peak load forecasts may be submitted.~~

The Parties acknowledge that additional information required to determine the Forecast Pool Requirement is to be obtained by the Office of the Interconnection from Electric Distributors in accordance with the provisions of the Operating Agreement.

SCHEDULE 13

EMERGENCY PROCEDURE CHARGES

Following an Emergency, the compliance of each Party with the instructions of the Office of the Interconnection shall be evaluated as ~~directed~~recommended by the Markets and Reliability Committee and directed by the PJM Board. If, based on such evaluation, it is determined that a Party refused to comply with, or otherwise failed to employ its best efforts to comply with, the instructions of the Office of the Interconnection to implement PJM emergency procedures, that Party shall pay an emergency procedure charge, as set forth in Attachment DD to the PJM Tariff. The revenue associated with Emergency Procedure Charges shall be allocated in accordance with Attachment DD to the PJM Tariff.

SCHEDULE 14

DELEGATION TO THE OFFICE OF THE INTERCONNECTION

The following responsibilities shall be delegated by the Parties to the Office of the Interconnection:

1. New Parties. With regard to the addition, withdrawal or removal of a Party the Office of the Interconnection shall:

   (a) Receive and evaluate the information submitted by entities that plan to serve loads within the PJM Region, including entities whose participation in the Agreement will expand the boundaries of the PJM Region. Such evaluation shall be conducted in accordance with the requirements of the Agreement.

   (b) Evaluate the effects of the withdrawal or removal of a Party from this Agreement.

2. Implementation of Reliability Assurance Agreement. With regard to the implementation of the provisions of this Agreement the Office of the Interconnection shall:

   (a) Receive all required data and forecasts from the Parties and other owners or providers of Capacity Resources;

   (b) Perform all calculations and analyses necessary to determine the Forecast Pool Requirement and the capacity obligations imposed under the Reliability Assurance Agreement, including periodic reviews of the capacity benefit margin for consistency with the Reliability Principles and Standards;

   (c) Monitor the compliance of each Party with its obligations under the Agreement;

   (d) Keep cost records, and bill and collect any costs or charges due from the Parties and distribute those charges in accordance with the terms of the Agreement;

   (e) Assist with the development of rules and procedures for determining and demonstrating the capability of Capacity Resources;

   (f) Establish the capability and deliverability of Generation Capacity Resources consistent with the requirements of the Reliability Assurance Agreement;

(g) Establish standards and procedures for Planned Demand Resources;

(h) Collect and maintain generator availability data;

(i) Perform any other forecasts, studies or analyses required to administer the Agreement;

(j) Coordinate maintenance schedules for generation resources operated as part of the PJM Region;

(k) Determine and declare that an Emergency exists or has ceased to exist in all or any part of the PJM Region or announce that an Emergency exists or ceases to exist in a Control Area interconnected with the PJM Region;

(l) Enter into agreements for (i) the transfer of energy in Emergencies in the PJM Region or in a Control Area interconnected with the PJM Region and (ii) mutual support in such Emergencies with other Control Areas interconnected with the PJM Region; and

(m) Coordinate the curtailment or shedding of load, or other measures appropriate to alleviate an Emergency, to preserve reliability in accordance with FERC, NERC or Applicable Regional Reliability Council principles, guidelines, standards, and requirements and the PJM Manuals, and to ensure the operation of the PJM Region in accordance with Good Utility Practice.

Attachment C
(Clean Sections)

PJM Open Access Transmission Tariff
(Clean Sections)

110.1 Application

The Generation Interconnection Customer desiring the interconnection of a new Generation Capacity Resource of 20 MW or less or the increase in capacity, by 20 MW or less, of an Existing Generation Capacity Resource, must submit a completed Attachment N – Form of Generation Interconnection Feasibility Study Agreement. Attachment N of the PJM Tariff may be found on the PJM web site at and must be submitted to Transmission Provider.

All requirements related to the submission, for a larger resource, of an Attachment N application must be satisfied for a capacity addition of 20 MW or less, including (i) an initial deposit in the amount of $100 for each MW requested if the Generation Interconnection Request is received within the first calendar month of the current New Services Queue; an initial deposit in the amount of $150 for each MW requested if the Generation Interconnection Request is received within the second calendar month of the current New Services Queue; or an initial deposit in the amount of $200 for each MW requested, if the Generation Interconnection Request is received within the third calendar month of the current New Services Queue; and (ii) a base non-refundable deposit in the amount of $1,000, if the Generation Interconnection Request is received within the first calendar month of the current New Services Queue; a base non-refundable deposit in the amount of $2,000 if the Generation Interconnection Request is received within the second calendar month of the current New Services Queue; or a base non-refundable deposit of $3,000, if the Generation Interconnection Request is received within the third calendar month of the current New Services Queue.

The base and initial per MW deposit received will be credited toward the Generation Interconnection Customer's cost responsibility for the Generation Interconnection Feasibility Study. Upon completion of the Feasibility Study, the Transmission Provider will return any unused refundable deposit monies to Interconnection Customer. Any remaining non-refundable deposit monies will be credited toward the Interconnection Customer's cost responsibility for any other studies conducted for that Interconnection Request under Part VI of the Tariff, which will be applied prior to the deposit monies collected for that other study. If any non-refundable deposit monies remain after all studies are complete, such monies will be returned to a Generation Interconnection Customer upon Initial Operation, or to a Transmission Interconnection Customer upon energization of completed facilities as provided in Attachment GG, Appendix III, Section 20 of the Tariff. The Generation Interconnection Customer is responsible for all actual costs associated with the processing of the request and the performance of the Feasibility Study related to the request and will be billed for such costs following the completion of the Feasibility Study.

Documentation of site control must be submitted, for small resource additions, with the completed Attachment N. Site control may be demonstrated through an exclusive option to purchase the property on which the generation project is to be developed, a property deed, or a range of tax or corporate documents that identify property ownership. Site control must either be in the name of the party submitting the generation interconnection request or documentation must be provided establishing the business relationship between the project developer and the party having site control.

All information required in the completed Attachment N related to the generating project site, Point of Interconnection, and generating unit size and configuration must be provided.
Once it has been established that the requirements related to the submission of the Attachment N application have been met, the Generation Interconnection Request will be entered into the then current New Services Queue for analysis. The generation addition project will be identified in the New Services Queue on the PJM web site by the size of the capacity addition and by its proposed Point of Interconnection on the PJM system.

110.5 Interconnection Service Agreement

As with larger generation projects, an Interconnection Service Agreement must be executed and filed with the FERC. The Interconnection Service Agreement identifies the obligations, on the part of the Interconnection Customer, to pay for transmission facilities required to facilitate the interconnection and the Capacity Interconnection Rights which are awarded to the *Generation* Capacity Resource.

In general, the execution of an Interconnection Service Agreement is no different for capacity additions of 20 MW or less than for larger *Generation* Capacity Resources. However, in instances where an increase of 20 MW or less to an Existing *Generation* Capacity Resource can be put in service immediately, a modified Interconnection Service Agreement may be executed. If such an increase is expedited through the System Impact Study phase, ahead of larger projects already in the New Services Queue, an Interconnection Service Agreement will be executed granting interim Capacity Interconnection Rights. These interim rights will allow the capacity increase to be implemented and the resource to participate in the capacity market until studies have been completed for earlier queued resources and all related obligations have been defined. At such time, the interim rights awarded the smaller capacity addition will become dependent on the construction of any required transmission facilities and the satisfaction of any financial obligations for those facilities. If, once those obligations are defined, the smaller capacity addition desires to retain the interim Capacity Interconnection Rights; a new Interconnection Service Agreement will be executed.

If a new Generation Capacity Resource of 20 MW or less can be quickly connected to the system, interim Capacity Interconnection Rights can be awarded, as above, through the execution of a modified Interconnection Service Agreement.

SCHEDULE 2
Reactive Supply and Voltage Control from Generation or Other Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided directly by the Transmission Provider. The Transmission Customer must purchase this service from the Transmission Provider.

In addition to the charges and payments set forth in this Schedule 2, Market Sellers providing reactive services at the direction of the Office of the Interconnection shall be credited for such services, and Market Participants shall be charged for such services, as set forth in section 3.2.3B of the Appendix to Attachment K.

The Transmission Provider shall administer the purchases and sales of Reactive Supply. PJMSettlement shall be the Counterparty to (a) the purchases of Reactive Supply from owners of Generation or Other Sources and Market Sellers and (b) the sales of Reactive Supply to Transmission Customers and Market Participants.

Charges

Purchasers of Reactive Supply and Voltage Control from Generation or Other Sources Service shall be charged for such service in accordance with the following formulae.

Monthly Charge for a purchaser receiving Network Integration Transmission Service or Point-to-Point Transmission Service to serve Non-Zone Load = Allocation Factor * Total Generation or other source Owner Monthly Revenue Requirement

Monthly Charge for a purchaser receiving Network Integration Transmission Service or Point-to-Point Transmission Service to serve Zone Load = Allocation Factor * Zonal Generation or other source Owner Monthly Revenue Requirement * Adjustment Factor

Where:

Purchaser serving Non-Zone Load is a Network Customer serving Non-Zone Network Load or serving Network Load in a zone with no revenue requirement

for Reactive Supply and Voltage Control from Generation or Other Sources Service, or a Transmission Customer where the Point of Delivery is at the boundary of the PJM Region.

Zonal Generation or other source Owner Monthly Revenue Requirement is the sum of the monthly revenue requirements for each generator or other source located in a Zone, as such revenue requirements have been accepted or approved, upon application, by the Commission.

Total Generation or other source Owner Monthly Revenue Requirement is the sum of the Zonal Generation or other source Owner Monthly Revenue Requirements for all Zones in the PJM Region.

Allocation Factor is the monthly transmission use of each Network Customer or Transmission Customer per Zone or Non-Zone, as applicable, on a megawatt basis divided by the total transmission use in the Zone or in the PJM Region, as applicable, on a megawatt basis.

For Network Customers, monthly transmission use on a megawatt basis is the sum of a Network Customer's daily values of DCPZ or DCPNZ (as those terms are defined in Section 34.1) as applicable, for all days of the month.

For Transmission Customers, monthly transmission use on a megawatt basis is the sum of the Transmission Customer's hourly amounts of Reserved Capacity for each day of the month (not curtailed by PJM) divided by the number of hours in the day.

Adjustment Factor is determined as the sum of the total monthly transmission use in the PJM Region, exclusive of such use by Transmission Customers serving Non-Zone Load, divided by the total monthly transmission use in the PJM Region on a megawatt basis.

In the event that a single customer is serving load in more than one Zone, or serving Non-Zone Load as well as load in one or more Zones, or is both a Network Customer and a Transmission Customer, the Monthly Charge for such a customer shall be the sum of the Monthly Charges determined by applying the appropriate formulae set forth in this Schedule 2 for each category of service.

Payment to Generation or Other Source Owners

Each month, the Transmission Provider shall pay each Generation or other source Owner an amount equal to the Generation or other source Owner's monthly revenue requirement as accepted or approved by the Commission. In the event a Generation or other source Owner sells a Generation Capacity Resource(s) which is included in its current effective monthly revenue requirement accepted or approved by the Commission, payments in that Generation or other

source Owner's Zone may be allocated as agreed to by the owners of Generation Capacity Resources in that Zone. Such Generation or other source Owners shall inform Transmission Provider of any such agreement. In the absence of agreement among such Generation or other source Owners, the Commission, upon application, shall establish the allocation. Generation Owners shall not be eligible for payment, pursuant to this Schedule 2, of monthly revenue requirement associated with those portions of generating units designated as Behind The Meter Generation. The Transmission Provider shall post on its website a list for each Zone of the annual revenue requirements for each Generation Owner receiving payment within such Zone and specify the total annual revenue requirement for all of the Transmission provider.

SCHEDULE 3
Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line resources whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The amount of and charges for Regulation and Frequency Response Service are set forth below. The Transmission Provider shall administer the purchases of Regulation Service in the PJM Interchange Energy Market. PJMSettlement shall be the Counterparty to the purchases by customers of Regulation Service in the PJM Interchange Energy Market; provided however, that PJMSettlement shall not be the contracting party to bilateral transactions between market participants or with respect to a self-schedule or self-supply of resources by a customer to satisfy its Regulation obligation.

For Regulation not satisfied by individual Transmission Owners on behalf of their Native Load Customers, Network Customers or other Transmission Customers serving load in the PJM Region, the Transmission Provider will order the lowest cost alternative for Regulation in service as needed to meet the Regulation requirements of each Regulation Zone (as may be set forth in the PJM Manuals and as specified below:

a. Regulation shall be supplied to meet the Regulation objective of a Regulation Zone from resources located within the metered electrical boundaries of such Regulation Zone. Resources offering Regulation shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the procedures of the Office of the Interconnection.

b. The Office of the Interconnection shall obtain and maintain an amount of Regulation for each Regulation Zone equal to the Regulation objective for such Regulation Zone, as specified in its procedures.

c. The Regulation range of a resource shall be at least twice the amount of Regulation assigned.

d. A resource capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced from the Regulation range by twice the amount of the Regulation provided. The amount of Regulation provided by a resource shall serve to redefine the normal minimum generation and normal maximum generation energy limits of that unit, in that the amount of Regulation shall be added to the unit's normal minimum generation energy limit, and subtracted from its normal maximum generation energy limit.

e. Qualified Regulation must satisfy the verification tests described in the procedures of the Office of the Interconnection.

f. A Transmission Owner, Network Customer or other Transmission Customer may satisfy its Regulation obligation from its own resources capable of performing Regulation service, by contractual arrangements with others able to provide Regulation service on a comparable basis, or by purchases from the PJM Regulation market.

g. The Office of the Interconnection shall obtain Regulation service from the least-cost alternatives available from either pool-scheduled or self-scheduled resources as needed to meet Regulation Zone requirements not otherwise satisfied by a Transmission Owner, Network Customer or other Transmission Customer, in accordance with Section 1.11.4(b) of Attachment K-Appendix.

h. The Office of the Interconnection shall dispatch resources for Regulation by sending Regulation signals and instructions to resources from which Regulation service has been offered, in accordance with the procedures of the Office of the Interconnection. Those resources shall comply with Regulation dispatch signals and instructions transmitted by the Office of the Interconnection and, in the event of conflict, Regulation dispatch signals and instructions shall take precedence over energy dispatch signals and instructions. Those providing Regulation shall exert all reasonable efforts to operate, or ensure the operation of, their resources supplying load in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

i. Each Transmission Owner (on behalf of its Native Load Customers), Network Customer or other Transmission Customer serving load within a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for such hour, based on the entity's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for such hour.

j. An entity supplying Regulation at the direction of the Office of the Interconnection in excess of its hourly Regulation obligation shall be credited for each increment of such Regulation at the price specified in Sections 3.2.2 and 3.3.2 of Attachment K-Appendix. A Transmission Owner, Network Customer or other Transmission Customer that does not meet its hourly Regulation obligation shall be charged for Regulation dispatched by the Office of the Interconnection to meet such obligation at the price specified in Sections 3.2.2 and 3.3.2 of Attachment K-Appendix.

SCHEDULE 6A
Black Start Service

References to section numbers in this Schedule 6A refer to sections of this Schedule 6A, unless otherwise specified.

To ensure the reliable restoration following a shut down of the PJM transmission system, Black Start Service is necessary to facilitate the goal of complete system restoration. Black Start Service enables Transmission Provider and Transmission Owners to designate specific generators called Black Start Units whose location and capabilities are required to re-energize the transmission system following a system-wide blackout. The Transmission Provider shall administer the provision of Black Start Service. PJMSettlement shall be the Counterparty to the purchases and sales of Black Start Service.

TRANSMISSION CUSTOMERS

1. All Transmission Customers and Network Customers must obtain Black Start Service through the Transmission Provider, with PJMSettlement as the Counterparty, pursuant to this Schedule 6A.

PROVISION OF BLACK START SERVICE

2. A Black Start Unit is a generating unit that has equipment enabling it to start without an outside electrical supply or a generating unit with a high operating factor (subject to Transmission Provider concurrence) with the demonstrated ability to automatically remain operating, at reduced levels, when disconnected from the grid. A Black Start Unit shall be considered capable of providing Black Start Service only when it meets the criteria set forth in the PJM manuals. For the purposes of this Schedule 6A, the expected life of the Black Start Unit shall take into consideration expectations regarding both the enabling equipment and the generation unit itself.

3. A Black Start Plant is a generating plant that includes one or more Black Start Units. A generating plant with Black Start Units electrically separated at different voltage levels will be considered multiple Black Start Plants.

4. The Transmission Provider, in conjunction with the Transmission Owners, are responsible for developing a coordinated and efficient system restoration plan that identifies all of the locations where Black Start Units are needed. The PJM Manuals shall set forth the criteria and process for selecting or identifying the Black Start Units necessary to commit to providing Black Start Service at the identified locations.. No more than three Black Start Units at a Black Start Plant will be eligible for compensation under this Schedule 6A, unless specifically approved by the Transmission Provider as an exception. No Black Start Unit shall be eligible to recover the costs of providing Black Start Service in the PJM Region unless it agrees to provide such service for a term of commitment established under section 5 or 6 below.

5. Owners of Black Start Units selected to provide Black Start Service in accordance with section 4 and electing to forego any recovery of new or additional Black Start Capital Costs shall

commit to provide Black Start Service from such Black Start Units for an initial term of no less than two years and authorize the Transmission Provider to resell Black Start Service from its Black Start Units. The term commitment shall continue to extend until the Black Start Unit owner, or the Transmission Owner, with the consent of the Transmission Provider, or the Transmission Provider, with the consent of the Transmission Owner, provides written, one-year advance notice of its intention to terminate the commitment.

6. Owners of Black Start Units selected to provide Black Start Service in accordance with section 4 and electing to recover new or additional Black Start Capital Costs shall commit to provide Black Start Service from such Black Start Units for a term based upon *the age of* the Black Start Unit *or the longest expected life of the Incremental Black Start Capital Cost*, as set forth in the *applicable* CRF Tables in Paragraph 18. *For those Black Start Units that elect to recover new or additional Black Start Capital Costs in addition to a prior, FERC-approved cost recovery rate, the applicable commitment period shall be the longer of the FERC-approved recovery period or the applicable term of commitment as set forth in the CRF Tables in Paragraph 18.* Either the Transmission Provider, with the consent of the Transmission Owner, or the Transmission Owner, with the consent of the Transmission Provider, may terminate the commitment with one year advance notice of its intention to the Black Start Unit owner, but the Transmission Owner shall reimburse the Black Start Unit owner for any amount of unrecovered Fixed Black Start Service Costs over a period not to exceed five years. A Black Start Unit owner may terminate the provision of Black Start Service with one year advance notice (or its commitment period may be involuntarily terminated pursuant to the section 15 below). Such Black Start Unit shall forego any otherwise existing entitlement to future revenues collected pursuant to this Schedule 6A and fully refund any amount of the Black Start Capital Costs recovered under a FERC-approved rate (recovered on an accelerated basis pursuant to the provisions of section 17(i)) in excess of the amount that would have been recovered pursuant to section 18 during the same period. At the conclusion of the term of commitment established under this section 6, a Black Start Unit shall commence a new term of commitment under either section 5 or 6, as applicable.

6A. In the event that a Black Start Unit fails to fulfill its commitment established under section 5 to provide Black Start Service, receipt of any Black Start Service revenues associated with the non-performing Black Start Unit shall cease and, for the period of the unit's non-performance, the Black Start Unit owner shall forfeit the Black Start Service revenues associated with the non-performing Black Start Unit that it received or would have received had the Black Start Unit performed, not to exceed revenues for a maximum of one year.

In the event that a Black Start Unit fails to fulfill its commitment established under section 6 above, such unit shall forego any otherwise existing entitlement to future revenues collected pursuant to this Schedule 6A and fully refund any amount of the Black Start Capital Costs recovered under a FERC-approved rate (recovered on an accelerated basis pursuant to the provisions of section 17(i)) in excess of the amount that would have been recovered pursuant to section 18 during the same period, but such unit remains eligible to establish a new commitment under section 5 or 6.

Performance Standards and Outage Restrictions

7. Black Start Units must have the capabilities listed below. These capabilities must be demonstrated in accordance with the criteria set forth in the PJM manuals and will remain in effect for the duration of the commitment to provide Black Start Service.

a. A Black Start Unit must be able to close its output circuit breaker to a dead (de-energized) bus within 90 minutes of a request from the Transmission Owner or the Transmission Provider.

b. A Black Start Unit must be capable of maintaining frequency and voltage under varying load.

c. A Black Start Unit must be able to maintain rated output for a period of time identified by each Transmission Owner's system restoration requirements, in conjunction with the Transmission Provider.

8. Each owner of Black Start Units or Black Start Plants must maintain procedures for the start-up of the Black Start Units.

9. If a Black Start Unit is a generating unit with a high operating factor (subject to Transmission Provider concurrence) with the ability to automatically remain operating at reduced levels when disconnected from the grid, this ability must be demonstrated in accordance with the criteria set forth in the PJM manuals.

10. No more than one Black Start Unit at a Black Start Plant may be subject to planned maintenance at any one time. This restriction excludes outages on common plant equipment that may make all units unavailable. A Black Start Unit not currently designated as critical and on the same voltage level may be substituted for a Black Start Unit that is subject to a planned outage to permit a concurrent planned outage of another critical Black Start Unit at the Black Start Plant to begin. The Black Start Unit used as a substitute must have had a valid annual test within the previous 12 months.

11. Concurrent planned outages at multiple Black Start Plants within a zone may be restricted based on Transmission Owner requirements for Black Start Service availability. Such restrictions must be predefined and approved by Transmission Provider in accordance with the PJM manuals.

Testing

12. To verify that they can be started and operated without being connected to the Transmission System, Black Start Units designated as critical shall be tested annually in accordance with the PJM manuals. The Black Start Unit owner shall determine the time of the annual test.

13. Compensation for energy output delivered to the Transmission System during the annual test shall be provided for the Black Start Unit's minimum run time at the higher of the unit's

cost-capped offer or real-time Locational Marginal Price plus start-up and no-load costs for up to two start attempts, if necessary. For Black Start Units that are generating units with a high operating factor (subject to Transmission Provider's concurrence) with the ability to automatically remain operating at reduced levels when disconnected from the grid, an opportunity cost will be provided to compensate the unit for lost revenues during testing.

14. To receive Black Start Service revenues, a Black Start Unit must have a successful annual test on record with the Transmission Provider within the preceding 13 months.

15. If a Black Start Unit fails the annual test, the unit may be re-tested within a ten-day period without financial penalty. If the Black Start Unit does not successfully re-test within that ten-day period, monthly Black Start Service revenues will be forfeited by that unit from the time of the first unsuccessful test until such time as the unit passes an annual test. If the Black Start Unit owner determines not to make the necessary repairs to enable the Black Start Unit to pass the annual test, the Black Start Unit owner will have failed to fulfill its commitment pursuant to section 5 or section 6, whichever is applicable, of this Schedule 6A and will be subject to the additional forfeiture of revenues set forth in section 6A.

Revenue Requirements

16. The annual Black Start Service revenue requirement shall be the sum of the annual Black Start Service revenue requirements for each generator that is designated as providing Black Start Service and has provided the Transmission Provider with a calculation of its annual Black Start Service revenue requirements. A separate line item shall appear on the participants' Transmission Provider bill for Black Start Service charges and credits.

17. Black Start Service revenue requirements for each Black Start Unit shall be based, at the election of the owner, on either (i) a FERC-approved rate for the recovery of the cost of providing such service for the entire duration of the commitment term set forth in either section 5 or 6, as applicable, or (ii) the formula *rates* set forth in section 18 of this Schedule 6A for the commitment term set forth in *Paragraph* 5 or 6 as applicable. Each generator's Black Start Service revenue requirements shall be an annual calculation. Requests for changes to the Black Start Service revenue requirements must be submitted to the Market Monitoring Unit for review and analysis, with supporting data and documentation, pursuant to section III of Attachment M – Appendix and the PJM Manuals. The Market Monitoring Unit and the generator owner shall attempt to come to agreement on the level of each component included in the Black Start Service revenue requirements. The Black Start Service generator owner may submit Black Start Service revenue requirements that it chooses, provided that (i) it has participated in good faith with the process described in this section and in section III of Attachment M - Appendix, (ii) the Black Start Service revenue requirements are no higher than the level defined in any agreement reached by the Black Start Service generator owner and the Market Monitoring Unit that resulted from the foregoing process, and (iii) the Black Start Service revenue requirements are accepted by the Office of the Interconnection subject to the criteria set forth in the Tariff.

In the event that the Black Start Service generator owner and Market Monitoring Unit cannot agree on the level of each component included in the calculation of the Black Start Service

revenue requirements, and the Black Start Service generator owner submits its own values to the Office of the Interconnection that are inconsistent with the Market Monitoring Unit's determination, the Office of the Interconnection shall determine whether to accept such values subject to the requirements of the Tariff and the PJM Manuals. If the Office of the Interconnection does not accept the values submitted by the Black Start Service generator owner in such case, the Black Start Service generator owner may file its proposed values with the Commission for approval. Pursuant to section III of Attachment M - Appendix, if the Office of the Interconnection accepts the Black Start Service revenue requirements submitted by the Black Start Service generator owner in such case, the Market Monitoring Unit may petition the Commission for an order that would require the Black Start Service generator to utilize the values determined by the Market Monitoring Unit or such other values as determined by the Commission. No change to a Black Start Service revenue requirement shall become effective until the existing revenue requirement has been effective for at least twelve months.

18. The formula for calculating a generator's annual Black Start Service revenue requirement is:

{(Fixed BSSC) + (Variable BSSC) + (Training Costs) + (Fuel Storage Costs)} * (1 + Z)

For units that have the demonstrated ability to operate at reduced levels when automatically disconnected from the grid, the formula is revised to:

(Training Costs) * (1+ Z)

where:

Fixed BSSC

Black Start Units with a commitment established under *Paragraph* 5 shall calculate Fixed BSSC or "Fixed Black Start Service Costs" in accordance with the following *Base Formula Rate*:

Base Formula Rate:

***Net* CONE * Black Start Unit Capacity * X**

Where:

"*Net* CONE" is the then current *installed capacity ("ICAP")* net Cost of New Entry *(expressed in $/MW year)* for the CONE Area where the Black Start Unit is located.

"Black Start Unit Capacity" is the Black Start Unit's installed capacity, expressed in MW.

"X" is the Black Start Service allocation factor unless a higher or lower value is supported by the documentation of the actual costs of providing Black Start Service. For such units qualifying as Black Start Units on the basis of demonstrated ability to operate at reduced levels when automatically disconnected from the grid, X shall be zero. For Black Start Units with a commitment established under section 5, X shall be .01 for Hydro units, .02 for Diesel or CT units.

Black Start Units with a commitment established under *Paragraph* 6 above shall calculate Fixed BSSC or "Fixed Black Start Service Costs" in accordance with *one of* the following formulas*, as applicable*:

Capital Cost Recovery Rate – NERC-CIP Specific Recovery

*(Net Cone * Black Start NERC-CIP Unit Capacity * X) + (Incremental Black Start NERC-CIP Capital Costs * CRF)*

Where:

"Net Cone" is the then current installed capacity ("ICAP") net Cost of New Entry (expressed in $/MW year) for the CONE are where the Black Start Unit is located.

"Black Start NERC-CIP Unit Capacity" is the Black Start Unit's installed capacity, expressed in MW, but, for purposes of this calculation, capped at 100 MW for Hydro units, or 50 MW for Diesel or CT units.

"Incremental Black Start NERC-CIP Capital Cost" are those capital costs documented by the owner or accepted by the Commission for the incremental equipment solely necessary to enable a Black Start Unit to maintain compliance with mandatory Critical Infrastructure Protection Reliability Standards (as approved by the Commission and administered by the applicable Electric Reliability Organization).

"CRF" or "Capital Recovery Factor" is equal to the levelized CRF as set forth in the applicable CRF Table set forth below.

A Black Start Unit may elect to terminate forward cost recovery under this Capital Cost Recovery Rate – NERC-CIP Specific Recovery at any time and seek cost recovery under the Capital Cost Recovery Rate, pursuant to the terms and conditions set forth below.

Capital Cost Recovery Rate

*(FERC-approved rate) + (Incremental Black Start Capital Costs * CRF)*

Where:

"FERC-approved rate" is the Black Start Unit's current FERC-approved recovery of costs to provide Black Start Service, if applicable.

"*Incremental* Black Start Capital Costs" *are* the *new or additional* capital cost*s* documented by the owner or accepted by the Commission for the incremental equipment solely necessary to enable a unit to provide Black Start Service in addition to whatever other product or services such unit may provide. Such costs shall include those incurred by a Black Start Owner in order to meet NERC Reliability Standards that apply to Black Start Units solely on the basis of the provision of Black Start Service by such unit. *However, Incremental Black Start Capital Costs shall not include any capital costs that the Black Start Unit owner is recovering for that unit pursuant to a FERC-approved recovery rate.*

"CRF" or "Capital Recovery Factor " is equal to the levelized CRF based on the age of the Black Start Unit, which is modified to provide Black Start Service, as present in the CRF Table *below*:

Age of Black Start Unit	*Term of Black Start Commitment*	Levelized CRF
1 to 5	20	0.125
6 to 10	15	0.146
11 to 15	10	0.198
16+	5	0.363

Or:

Optionally, a Black Start Unit owner may elect to apply an alternative Capital Recovery Factor, in lieu of the age-based CRF Table listed above, which is based upon to the expected Capital Improvement Lifespan of the new or additional capital improvements (as determined by the applicable depreciation period of the capital improvement, as published from time to time by the US Internal Revenue Service). The applicable term of Black Start Service commitment shall be equal to the Capital Improvement Lifespan. In the event that the Black Start Unit seeks recovery of capital improvements that are included in more than one category of Capital Improvement Lifespan (as set forth below), its applicable commitment to provide black start service for such Black Start Unit shall be the longest expected life of those new or additional capital improvements.

Capital Improvement Lifespan (Years)	*Levelized CRF*
16-20	*0.125*
11-15	*0.146*
6-10	*0.198*

1-5	*0.363*

In those circumstances where a Black Start Unit owner has elected to recover Incremental Black Start Capital Costs, in addition to a FERC-approved recovery rate, its applicable term of commitment shall be the greater of: (i) the FERC-approved recovery period, or; (ii) the applicable term of commitment as established by the CRF Tables above.

A Black Start Unit may make a non-revocable election to forego calculation of its Fixed BSSC, and surrender any forward compensation that it otherwise would have been entitled to, in accordance with either Capital Cost Recovery Rate set forth above. In this case, the Black Start Unit shall calculate its Fixed BSSC in accordance with the Base Formula Rate (and provide the applicable term of commitment established in Paragraph 5 above). In the event that the Black Start Unit seeks to recover further new or additional Black Start Capital Costs, it may not seek to recover any portion of those Black Start Capital Costs as its Fixed BSSC that it had previously forfeited.

After a Black Start Unit has recovered its allowable Incremental Black Start Capital Costs or Incremental Black Start NERC-CIP Capital Costs, as provided by the applicable Capital Cost Recovery Rate, and has satisfied its applicable commitment period required under Paragraph 6, the Black Start Unit shall be committed to providing black start in accordance with Paragraph 5 of this Schedule 6A and calculate its Fixed BSSC in accordance with the Base Formula Rate.

Variable BSSC

All Black Start Units shall calculate Variable BSSC or "Variable Black Start Service Costs" in accordance with the following formula:

Black Start Unit O&M * Y

Where:

"Black Start Unit O&M" are the operations and maintenance costs attributable to supporting Black Start Service and must equal the annual variable O&M outlined in the PJM Cost Development *Guidelines set forth in the PJM Manuals*. Such costs shall include those incurred by a Black Start Owner in order to meet NERC Reliability Standards that apply to the Black Start Unit solely on the basis of the provision of Black Start Service by unit.

"Y" is 0.01, unless a higher or lower value is supported by the documentation of costs. If a value of Y is submitted for this cost, a (1-Y) factor must be applied to the Black Start Unit's O&M costs on the unit's cost-based energy schedule, calculated based on the Cost *Development* Guidelines in the PJM *Manuals*.

For units qualifying as Black Start Units on the basis of a demonstrated ability to operate at reduced levels when automatically disconnected from the grid, there are no variable

costs associated with providing Black Start Service and the value for Variable BSSC shall be zero.

Training Costs:

All Black Start Units shall calculate Training Costs in accordance with the following formula:

50 staff hours/year/plant*75/hour

Fuel Storage Costs:

Black Start Units that cannot use oil for fuel shall *calculate* Fuel Storage Costs or "FSC" as zero. Black Start Units that can use oil for fuel shall calculate Fuel Storage Costs in accordance with the following formula:

{MTSL + [(# Run Hours) * (Fuel Burn Rate)]} *
(12 Month Forward Strip + Basis) * (Bond Rate)Where:

Run Hours are the actual number of hours a Transmission Provider requires a Black Start Unit to run. Run Hours shall be at least 16 hours or as defined by the Transmission Owner restoration plan, whichever is less.

"Fuel Burn Rate" is actual fuel burn rate for the Black Start Unit.

"12-Month Forward Strip" is the average of forward prices for the fuel burned in the Black Start Unit.
"Basis" is the transportation costs from the location referenced in the forward price data to the Black Start Unit plus any variable taxes.
"Bond rate" is the value determined with reference to the Moody's Utility Index for bonds rated Baa1.
"MTSL" is the "minimum tank suction level" and shall apply where no direct current pumps are available for the Black Start Unit.

For units qualifying as Black Start Units on the basis of a demonstrated ability to operate at reduced levels when automatically disconnected from the grid, there are no associated fuel storage costs and the value for FSC shall be zero.

Z

Z shall be an incentive factor for Black Start Units with a commitment established under section 5 above and shall be ten percent.

At least every two years, PJM shall review the formula and its costs components set forth in this section, and report on the results of that review to stakeholders.

19. Transmission Provider or its agent shall have the right to independently audit the accounts and records of each Black Start Unit that is receiving payments for providing Black Start Service.

20. PJM shall notify its Members when a Black Start Unit seeks to recover new or additional Black Start NERC-CIP Capital Costs under Paragraph 18 no later than thirty (30) days prior to the effective date of the recovery. At the written request of any PJM Member, made simultaneously to the Market Monitoring Unit and PJM, with notice to the Black Start Unit owner, the Market Monitoring Unit shall make available to the PJM Member for inspection at the offices of the Market Monitoring Unit, all data supporting the requested new or additional NERC-CIP specific Capital Costs. The Black Start Unit owner may elect to attend this review. In all cases, the supporting data is to be held confidential and may not be distributed.

21. The Market Monitoring Unit shall include a Black Start Service summary in its annual State of the Market report which will set forth a descriptive summary of the new or additional Black Start NERC-CIP Capital Costs requested by Black Start Units, and include a list of the types of capital costs requested and the overall cost of such capital improvements on an aggregate basis such that no data is attributable to an individual Black Start Unit.

Credits

22. Monthly credits are provided to generators that submit to the Transmission Provider their annual revenue requirements established pursuant to section 17 of this Schedule 6A. The generator's monthly credit is equal to 1/12 of its annual Black Start Service revenue requirement for eligible critical Black Start Units.

23. Revenue requirements for jointly owned Black Start Units will be allocated to the owners based on ownership percentage.

24. Transmission Provider shall not compensate generators for Black Start Service unless they meet the Transmission Provider and Applicable Regional Reliability Council criteria for Black Start Service and provide Transmission Provider with all necessary data in accordance with this Schedule 6A and the PJM manuals.

Charges

25. Zonal rates will be based on Black Start Service capability of generation units nominated by each transmission zone and allocated to network service customers and point-to-point reservations.

26. Revenue requirements for Black Start Units nominated by a Transmission Owner as critical (regardless of zonal location) will be allocated to the nominating Transmission Owner's zone.

27. Purchasers of Black Start Service shall be charged for such service in accordance with the following formulae.

Monthly Charge for a purchaser receiving Network Integration Transmission Service or Point-to-Point Transmission Service to serve Non-Zone Load = Allocation Factor * Total Generation Owner Monthly Black Start Service Revenue Requirement

Monthly Charge for a purchaser receiving Network Integration Transmission Service or Point-to-Point Transmission Service to serve Zone Load = Allocation Factor * Zonal Generation Owner Monthly Black Start Service Revenue Requirement * Adjustment Factor

Where:

Purchaser serving Non-Zone Load is a Network Customer serving Non-Zone Network Load or a Transmission Customer where the Point of Delivery is at the boundary of the PJM Region.

Zonal Generation Owner Monthly Black Start Service Revenue Requirement is the sum of the monthly Black Start Service revenue requirements for each generator nominated by the Transmission Owners in that zone.

Total Generation Owner Monthly Black Start Service Revenue Requirement is the sum of the Zonal Generation Owner Monthly Black Start Service Revenue Requirements for all Zones in the PJM Region.

Allocation Factor is the monthly transmission use of each Network Customer or Transmission Customer per Zone or Non-Zone, as applicable, on a megawatt basis divided by the total transmission use in the Zone or in the PJM Region, as applicable, on a megawatt basis.

For Network Customers, monthly transmission use on a megawatt basis is the sum of a Network Customer's daily values of DCPZ or DCPNZ (as those terms are defined in Section 34.1) as applicable, for all days of the month.

For Transmission Customers, monthly transmission use on a megawatt basis is the sum of the Transmission Customer's hourly amounts of Reserved Capacity for each day of the month (not curtailed by PJM) divided by the number of hours in the day.

Adjustment Factor is determined as the sum of the total monthly transmission use in the PJM Region on a megawatt basis, exclusive of such use by Network Customers and Transmission Customers serving Non-Zone Load, divided by the total monthly transmission use in the PJM Region on a megawatt basis.

In the event that a single customer is serving load in more than one Zone, or serving Non-Zone Load as well as load in one or more Zones, or is both a Network Customer and a Transmission Customer, the Monthly Charge for such a customer shall be the sum of the Monthly Charges determined by applying the appropriate formulae set forth in this Schedule 6A.

ATTACHMENT K

Transmission Congestion and Loss Charges and Credits

Preface.

This Attachment and Attachment K – Appendix specify the manner in which all Transmission Customers, Network Customers, and Transmission Owners using the Transmission System to serve their Native Load Customers and Marker Participants submitting virtual bids and offers will be charged for the costs of congestion and losses on the Transmission System, the manner in which all FTR holders share in the allocation of revenues received as Transmission Congestion Charges , and the manner in which Network Service Users, Market Participants in the PJM Interchange Energy Market and Transmission Customers share in the allocation of Transmission Loss Charges. In addition, Attachment K - Appendix incorporates into the Tariff for ease of reference the provisions of Schedule 1 of the Operating Agreement ("Schedule 1"). Capitalized terms used in this Attachment which are not defined in the Tariff or in the Attachment, but which are defined in Schedule 1 shall have the meanings set forth in Schedule 1.

A. Transmission Congestion and Loss Charges

1. [Reserved for Future Use]

2. [Reserved for Future Use]

3. [Reserved for Future Use]

4.

In determining the total billable amount of Transmission Congestion Charges, the Office of the Interconnection, on behalf of PJMSettlement, shall take into account and set-off against each other both positive Transmission Congestion Charges and negative Transmission Congestion Charges in accordance with Section 5 of Attachment K – Appendix. PJMSettlement shall exclude transactions on the PJM Interchange Energy Market in issuing a statement, invoice, or payment for the net amount owed for Transmission Congestion Charges for any period.

In determining the total billable amount of Transmission Loss Charges, the Office of the Interconnection, on behalf of PJMSettlement, shall take into account and set-off against each other both positive Transmission Loss Charges and negative Transmission Loss Charges in accordance with Section 5 of Attachment K – Appendix. PJMSettlement shall exclude transactions on the PJM Interchange Energy Market in issuing a statement, invoice, or payment for the net amount owed for Transmission Loss Charges for any period.

B. Transmission Congestion and Loss Credits.

1.

Financial Transmission Rights may be acquired by purchase in the Financial Transmission Rights auctions or in the secondary market provided for in Section 7 of Attachment K - Appendix.

Each holder of an FTR shall receive the total Transmission Congestion Credits determined in accordance with Section 5 of Attachment K - Appendix.
Each Network Service User and Transmission Customer shall receive an allocation of Transmission Loss Credits in accordance with Section 5 of Attachment K – Appendix.

2 [Reserved for Future Use]

C. [Reserved for Future Use]

D. Transmission Service Components.

Transmission Congestion Charges, Transmission Congestion Credits, Ancillary Services charges and credits, Transmission Loss Charges, Transmission Loss Credits and allocations of Financial Transmission Rights auction revenues are components of transmission service charges under Parts II and III of the Tariff and shall not give rise to separate transactions with PJMSettlement regarding the purchase or sale of electric energy.

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 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) In the Real-time Energy Market, Market Participants that deviate from the amounts of energy purchases or sales, or Transmission Customers that deviate from the transmission uses, scheduled in the Day-ahead Energy Market shall be obligated to purchase or sell energy, or 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.

(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 shall be conducted as specified 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.

1.10.1A Day-Ahead Energy Market Scheduling.

The following actions shall occur not later than 12:00 noon 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.

(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 bilateral transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection whether the transaction is to be included in the Day-ahead Energy Market. Any Market Participant that elects to include a bilateral transaction in the Day-ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the PJM Manuals), if any, at which it will be wholly or partially curtailed rather than pay Transmission Congestion Charges. The foregoing price specification shall apply to the price difference between the specified bilateral transaction source and sink points in the day-ahead scheduling process only. Any Market Participant that elects not to include its bilateral 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 Charges in the Real-time Energy Market in order to complete any such scheduled bilateral transaction. Scheduling of bilateral transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

i) Internal Market Buyers shall submit schedules for all bilateral purchases for delivery within the PJM Region, whether from generation resources inside or outside the PJM Region;

ii) Market Sellers shall submit schedules for bilateral sales to entities outside the PJM Region from generation within the PJM Region that is not dynamically scheduled to such entities pursuant to Section 1.12; and

iii) In addition to the foregoing schedules for bilateral transactions, Market Participants shall submit confirmations of each scheduled bilateral transaction from each

other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(d) Market Sellers wishing to sell into the Day-ahead Energy Market shall submit offers for the supply of energy (including energy from hydropower units), demand reductions, Regulation, Operating Reserves or other services for the following 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(d), Schedule 2 of the Operating Agreement, and the PJM Manuals, as applicable. 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 Attachment DD of the PJM Tariff, 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. The submission of offers for resource increments that have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, and PJM Manuals, as applicable. Energy offered from generation resources that have not cleared a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff 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 Demand Resource and energy or demand reduction amount, respectively, for each hour in the offer period, and the minimum run time for generation resources and minimum down time for Demand Resources;

ii) Shall specify the amounts and prices for the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;

iii) If based on energy from a specific generating unit, may specify start-up and no-load fees equal to the specification of such fees for such unit on file with the Office of the Interconnection, if based on reductions in demand from a Demand Resource may specify shutdown costs;

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 a second schedule 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, which offer shall remain open through the Operating Day for which the offer is submitted;

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; and

viii) Shall not exceed an energy offer price of $1,000/megawatt-hour.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation that shall specify the megawatt of Regulation being offered, which must equal or exceed 0.1 megawatts, the Regulation Zone for which such regulation is offered, the price of the offer in dollars per MWh, 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. The price of the offer shall not exceed $100 per MWh in the case of Regulation offered for all Regulation Zones. 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 heat rate increase resulting from operating a unit at lower megawatt output incurred from the provision of Regulation;

ii. The cost increase (in $/MW) in variable operating and maintenance costs resulting from operating the unit at lower megawatt output incurred from the provision of Regulation; and

iii. An adder of up to $12.00 per megawatt of Regulation provided.

Qualified Regulation capability must satisfy the 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 and no-load fees, 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.

(g) Each offer by a Market Seller of a Generation Capacity Resource 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 Increment Bids and/or Decrement Bids that apply to the Day-ahead Energy Market only. Such bids 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 3000 bid/offer segments in the Day-ahead Energy Market, 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 Bid or Decrement Bid.

(j) A Market Seller that wishes to make a generation resource or Demand Resource available to sell Synchronized Reserve shall submit an offer for Synchronized Reserve that shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.1 megawatts, the price of the offer in dollars per megawatt hour, and such other information specified by the Office of Interconnection as may be necessary to evaluate the offer and the energy used by the generation resource to provide the Synchronized Reserve and the generation resource's unit specific opportunity costs. The price of the offer shall not exceed the variable operating and maintenance costs for providing Synchronized Reserve plus seven dollars and fifty cents.

(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. The offer must equal or exceed 0.1 megawatts, and the offer 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; and (iii) at the Economic Load Response Participant's option, start-up 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. 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).

(l) Market Sellers owning or controlling the output of a Demand Resource that was committed in an FRR Capacity Plan, self-supplied or offered and cleared in the Base Residual

Auction or one of the Incremental Auctions, or owning or controlling the output of an ILR resource which was certified as specified in Attachment DD of the PJM Tariff, may submit demand reduction bids for the available load reduction capability of the Demand Resource or ILR resource. The submission of demand reduction bids for resource increments that have not cleared in the Base Residual Auction or in one of the Incremental Auctions, or for ILR resources that were not certified, or were not committed in an FRR Capacity Plan, shall be optional, but any such bids must contain the information specified in the PJM Economic Load Response Program to be included in such bids. A Demand Resource that was committed in an FRR Capacity plan, self-supplied or offered and cleared in a Base Residual Auction or an 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 Demand Resources and ILR 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) Market Sellers that wish to make Day-ahead Scheduling Reserves Resources available to sell Day-ahead Scheduling Reserves shall submit offers, each of which must equal or exceed 0.1 megawatts, in the Day-ahead Scheduling Reserves Market specifying: 1) the price of the offer in dollars per megawatt hour; and 2) such other information specified by the Office of the Interconnection as may be necessary to determine any relevant opportunity costs for the resource(s). The foregoing notwithstanding, to qualify to submit offers pursuant to this section, the Day-ahead Scheduling Reserves Resources shall submit energy offers in the Day-ahead Energy Market including start-up and shut-down costs for generation resource and Demand Resources, respectively, and all generation resources that are capable of providing Day-ahead Scheduling Reserves that a particular resource can provide that service. The MW quantity of Day-Ahead Scheduling Reserves that a particular resource can provide in a given hour will be determined based on the energy Offer Data submitted in the Day-ahead Energy Market, as detailed in the PJM Manuals.

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 Sections 1.10.9 or 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, start-up, no-load 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.

(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 and no-load fees, from the Office of the Interconnection on behalf of the Market Buyers in accordance with Section 3 of this Schedule 1. Alternatively, the Market Seller shall receive, in lieu of start-up and no-load fees, its actual costs incurred, if any, up to a cap of the resource's start-up cost, 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 offer must equal or exceed 0.1 megawatts, in minimum increments of .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 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, or otherwise not following the dispatch orders of 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.

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.

(c) A resource that has been self-scheduled shall not receive payments or credits for start-up or no-load fees.

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 dispatch 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 dispatch by the Office of the Interconnection shall be delivered on a block loaded basis to the bus or busses 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 busses.

(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.

1.10.6A Transmission Loading Relief Customers.

(a) An entity that desires to elect to pay Transmission Congestion Charges in order to continue its energy schedules during an Operating Day over contract paths outside the PJM Region in the event that PJM initiates Transmission Loading Relief that otherwise would cause PJM to request security coordinators to curtail such Member's energy schedules shall:

(i) enter its election on OASIS by 12:00 p.m. of the day before the Operating Day, in accordance with procedures established by PJM, which election shall be applicable for the entire Operating Day; and

(ii) if PJM initiates Transmission Loading Relief, provide to PJM, at such time and in accordance with procedures established by PJM, the hourly integrated energy schedules that impacted the PJM Region (as indicated from the NERC Interchange Distribution Calculator) during the Transmission Loading Relief.

(b) If an entity has made the election specified in Section (a), then PJM shall not request security coordinators to curtail such entity's energy transactions, except as may be necessary to respond to Emergencies.

(c) In order to make elections under this Section 1.10.6A, an entity must (i) have met the creditworthiness standards established by the Office of the Interconnection or provided a letter of credit or other form of security acceptable to the Office of the Interconnection, and (ii) have executed either the Agreement, a Service Agreement under the PJM Tariff, or other agreement committing to pay all Transmission Congestion Charges incurred under this Section.

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 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; (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 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) Not earlier than 4:00 p.m. 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.

(c) Following posting of the information specified in Section 1.10.8(b), 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 offer that set 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 offer that set the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Section 3.3A of this Schedule.

(e) If the Office of the Interconnection discovers an error in prices and/or cleared quantities in the Day-ahead Energy Market, Real-time Energy Market, Ancillary Services Markets or Day Ahead Scheduling Reserve Market after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants of the error 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 Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the second business day following the initial publication of the results for the Day-ahead Scheduling Reserve Market and Day-ahead Energy Market.

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, together with all available supporting documentation, by no later than 5:00 p.m. of the fifth business day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the fifth business day following the initial publication of the results in the Day-ahead Scheduling Reserve Market and the Day-ahead Energy Market. 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 Ancillary Services Markets, Day-

ahead Energy Market and Real-time Energy Market, and no later than 5:00 p.m. of the tenth calendar day following the initial publication of the results in the Day-ahead Scheduling Reserve Market. 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 Section 18.17.1 of the PJM Operating Agreement, 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, a generation rebidding period shall exist from 4:00 p.m. to 6:00 p.m. on the day before each Operating Day. During the rebidding period, Market Participants may submit revisions to generation Offer Data for any generation resource that was not selected as a pool-scheduled resource in the Day-ahead Energy Market. Adjustments to Day-ahead Energy Markets 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 10:00 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 60 minutes prior to the hour in which the adjustment is to take effect, as follows:

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 fee.

(c) With respect to a pool-scheduled resource that is included in the Day-ahead Energy Market, a Market Seller may not change or otherwise modify its offer to sell energy.

(d) 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 60 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.

(e) 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.

1.11 Dispatch.

The following procedures and principles shall govern the dispatch of the resources available to the Office of the Interconnection.

1.11.1 Resource Output.

The Office of the Interconnection shall have the authority to direct any Market Seller to adjust the output of any pool-scheduled resource increment within the operating characteristics specified in the Market Seller's offer. The Office of the Interconnection may cancel its selection of, or otherwise release, pool-scheduled resources, subject to an obligation to pay any applicable start-up, no-load or cancellation fees. The Office of the Interconnection shall adjust the output of pool-scheduled resource increments as necessary: (a) to maintain reliability, and subject to that constraint, to minimize the cost of supplying the energy, reserves, and other services required by the Market Buyers and the operation of the PJM Region; (b) to balance load and generation, maintain scheduled tie flows, and provide frequency support within the PJM Region; and (c) to minimize unscheduled interchange not frequency related between the PJM Region and other Control Areas.

1.11.2 Operating Basis.

In carrying out the foregoing objectives, the Office of the Interconnection shall conduct the operation of the PJM Region in accordance with the PJM Manuals, and shall: (i) utilize available generating reserves and obtain required replacements; and (ii) monitor the availability of adequate reserves.

1.11.3 Pool-dispatched Resources.

(a) The Office of the Interconnection shall implement the dispatch of energy from pool-scheduled resources with limited energy by direct request. In implementing mandatory or economic use of limited energy resources, the Office of the Interconnection shall use its best efforts to select the most economic hours of operation for limited energy resources, in order to make optimal use of such resources consistent with the dynamic load-following requirements of the PJM Region and the availability of other resources to the Office of the Interconnection.

(b) The Office of the Interconnection shall implement the dispatch of energy from other pool-dispatched resource increments, including generation increments from Capacity Resources the remaining increments of which are self-scheduled, by sending appropriate signals and instructions to the entity controlling such resources, in accordance with the PJM Manuals. Each Market Seller shall ensure that the entity controlling a pool-dispatched resource offered or made available by that Market Seller complies with the energy dispatch signals and instructions transmitted by the Office of the Interconnection.

1.11.3A Maximum Generation Emergency.

If the Office of the Interconnection declares a Maximum Generation Emergency, all deliveries to load that is served by Point-to-Point Transmission Service outside the PJM Region from Generation Capacity Resources committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative may be interrupted in order to serve load in the PJM Region.

1.11.4 Regulation.

(a) A Market Buyer may satisfy its Regulation Obligation from its own generation resources and/or Demand Resources capable of performing Regulation service, by contractual arrangements with other Market Participants able to provide Regulation service, or by purchases from the PJM Interchange Energy Market at the rates set forth in Section 3.2.2. PJMSettlement shall be the Counterparty to the purchases and sales of Regulation service in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Regulation Obligation.

(b) The Office of the Interconnection shall obtain Regulation service from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Demand Resources as needed to meet Regulation Zone requirements not otherwise satisfied by the Market Buyers. Generation resources or Demand Resources offering to sell Regulation shall be selected to provide Regulation on the basis of each generation resource's and Demand Resource's regulation offer and the estimated opportunity cost of a resource providing regulation and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Regulation, and other ancillary services. Estimated opportunity costs for generation resources shall be determined by the Office of the Interconnection on the basis of the expected value of the energy sales that would be foregone or uneconomic energy that would be produced by the resource in order to provide Regulation, in accordance with procedures specified in the PJM Manuals. Estimated opportunity costs for Demand Resources will be zero.

(c) The Office of the Interconnection shall dispatch resources for Regulation by sending Regulation signals and instructions to generation resources and/or Demand Resources from which Regulation service has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall comply with Regulation dispatch signals and instructions transmitted by the Office of the Interconnection and, in the event of conflict, Regulation dispatch signals and instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their resources supplying load in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4A Synchronized Reserve.

(a) A Market Buyer may satisfy its Synchronized Reserve obligation from its own generation resources and/or Demand Resources capable of providing Synchronized Reserve, by contractual arrangements with other Market Participants able to provide Synchronized Reserve,

or by purchases from the PJM Synchronized Reserve Market at the rates set forth in Section 3.2.3A. PJMSettlement shall be the Counterparty to the purchases and sales of Synchronized Reserve in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Synchronized Reserve Obligation.

(b) The Office of the Interconnection shall obtain Synchronized Reserve from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Demand Resources as needed to meet the Synchronized Reserve requirements of each Synchronized Reserve Zone of the PJM Region not otherwise satisfied by the Market Buyers. Resources offering to sell Synchronized Reserve shall be selected to provide Synchronized Reserve on the basis of each generation resource's and/or Demand Resource's Synchronized Reserve offer and the estimated unit specific opportunity cost of the resource providing Synchronized Reserve, and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Synchronized Reserve and other ancillary services. Estimated unit specific opportunity costs for generation resources shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the generation resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to 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, times (B) the absolute value of 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 Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources will be zero.

(c) The Office of the Interconnection shall dispatch generation resources and/or Demand Resources for Synchronized Reserve by sending Synchronized Reserve instructions to generation resources and/or Demand Resources from which Synchronized Reserve has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall comply with Synchronized Reserve dispatch instructions transmitted by the Office of the Interconnection and, in the event of a conflict, Synchronized Reserve dispatch instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their generation resources supplying load in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.5 PJM Open Access Same-time Information System.

The Office of the Interconnection shall update the information posted on the PJM Open Access Same-time Information System to reflect its dispatch of generation resources.

3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

(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 Section 2 of this Schedule

(b) Market Buyers shall be charged for all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price .

(c) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(d) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the total amount of net hourly PJM Interchange for each Market Buyer, including Generating Market Buyers, in accordance with the PJM Manuals. For Internal Market Buyers that are Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall include determination of the net energy flows from: (i) tie lines; (ii) any generation resource the output of which is controlled by the Market Buyer but delivered to it over another entity's Transmission Facilities; (iii) any generation resource the output of which is controlled by another entity but which is directly interconnected with the Market Buyer's transmission system; (iv) deliveries pursuant to bilateral energy sales; (v) receipts pursuant to bilateral energy purchases; and (vi) an adjustment to account for the day-ahead PJM Interchange, calculated as the difference between scheduled withdrawals and injections by that Market Buyer in the Day-ahead Energy Market. For External Market Buyers and Internal Market Buyers that are not Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall determine the energy scheduled hourly for delivery to the Market Buyer net of the amounts scheduled by such Market Buyer in the Day-ahead Energy Market.

(e) An Internal Market Buyer shall be charged for Spot Market Energy purchases to the extent of its hourly net purchases from the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. An External Market Buyer shall be charged for its Spot Market Energy purchases based on the energy delivered to it, determined as specified in Section 3.2.1(d) above. The total charge shall be determined by the product of the hourly net amount of PJM Interchange Imports times the hourly Real-time System Energy Price for that Market Buyer.

(f) A Generating Market Buyer shall be paid as a Market Seller for sales of Spot Market Energy to the extent of its hourly net sales into the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. The total payment shall be determined by the product of the hourly net amount of PJM Interchange Exports times the hourly Real-time System Energy Price for that Market Seller.

3.2.2 Regulation.

(a) Each Internal Market Buyer 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 requirements of such Regulation Zone for the hour, based on the Market Buyer'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"). An Internal Market Buyer that does not meet its hourly Regulation obligation shall be charged for Regulation dispatched by the Office of the Interconnection to meet such obligation at the Regulation market-clearing price determined in accordance with subsection (c) of this section, plus the amounts, if any, described in subsection (f) of this section.

(b) A Generating Market Buyer supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection in excess of its hourly Regulation obligation shall be credited for each increment of such Regulation at the higher of (i) the Regulation market-clearing price in such Regulation Zone or (ii) the sum of the regulation offer and the unit-specific opportunity cost of the generation resource supplying the increment of Regulation, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Regulation market-clearing price in each Regulation Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day. The market-clearing price for each regulating hour shall be equal to the highest sum of a resource's Regulation offer plus its estimated unit-specific opportunity costs, determined as described in subsection (d) below from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.3.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation market-clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour shall be equal to the sum of the unit-specific opportunity costs (i) incurred during the hour in which the obligation is fulfilled, plus costs (ii) associated with uneconomic operation during the hour preceding the initial regulating hour ("preceding shoulder hour"), plus costs (iii) associated with uneconomic operation during the hour after the final regulating hour ("following shoulder hour").

The unit-specific opportunity costs incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (a) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the resource's expected output during the preceding shoulder hour, times (b) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource during the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (c) the percentage of the preceding shoulder hour during which the deviation was incurred.

The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (a) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the resource's expected output in the following shoulder hour, times (b) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (c) the percentage of the following shoulder hour that the deviation was incurred.

Estimated opportunity costs for Demand Resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Generating Market Buyer 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 each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's Regulation signals from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour 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 hour in order to

provide Regulation and the lesser of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, 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 the following shoulder hour 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 hour in order to provide Regulation and the lesser of the resource's actual or expected output in the following shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the following shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the following shoulder hour during which the deviation was incurred, 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 Internal Market Buyer 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.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to section 1.10.1A(e) of this Schedule. A Regulation supplier fails the three-pivotal supplier test in any hour 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 three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region for which the cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The 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.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the prices offered 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 Section 3.2.3A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, 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 Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load fees 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. Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. 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 from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), 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.

(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 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 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 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 in the Day-ahead Energy Market.

(d) The cost of Operating Reserves 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 (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; 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 dynamically scheduled to load outside such area pursuant to Section 1.12.

(e) 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 or minimum run time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or minimum run time (minimum down time for Demand 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 (minimum down time for Demand Resources) and Segment 2 will include the remainder of the contiguous hours 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.

Credits received pursuant to this section shall be equal to the positive difference between a resource's total offered price for start-up (shutdown costs for Demand Resources) and no-load fees and energy, determined on the basis of the resource's scheduled output, and the total value of the resource's energy as determined by the Real-time Energy Market and 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 Demand 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) plus the resource's opportunity cost and less any amounts credited for Synchronized Reserve in excess of the Synchronized Reserve offer plus the resource's opportunity cost and less any amounts credited for Reactive Services as specified in Section 3.2.3.B, and less any amounts for Day-ahead Scheduling Reserve in excess of the Day-ahead Scheduling Reserve offer plus the resource's opportunity cost, shall be credited to the Market Seller.

Synchronized Reserve and Day-ahead Scheduling Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding hour(s) in which the Synchronized Reserve and Day-ahead Scheduling Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each hour the unit operates in condensing and generation mode.

(f) A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool-scheduled (or self-scheduled, if operating according to 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 hourly integrated, 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 hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

> 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 hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;
>
> AG equals the actual hourly integrated output of the unit;
>
> URTLMP equals the real time LMP at the unit's bus;
>
> UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UB shall not be negative.

(f-1) A Market Seller's combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section

1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost 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 above for a steam unit or combined cycle unit operating in combined cycle mode.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG, or (ii) {(URTLMP – UB) x DAG where:

URTLMP equals the real time LMP at the unit's bus;

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit, determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

(f-2) A Market Seller's hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to 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.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with 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, less any payments received from another Control Area for Operating Reserves, plus any redispatch costs incurred in accordance with section 10(a) of this Schedule, shall be 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 shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (i) load deviations (net of operating Behind The Meter Generation) from the Day-ahead Energy Market in megawatt-hours during that Operating Day, except as noted below and in the PJM Manuals; (ii) generation deviations (not including deviations in Behind The Meter Generation) from the Day-ahead Energy Market for non-dispatchable generation resources, including External Resources, in megawatt-hours during the Operating Day; (iii) deviations from the Day-ahead Energy Market for bilateral transactions from outside the PJM Region for delivery within such region in megawatt-hours during the Operating Day; and (iv) deviations of energy sales from the Day-ahead Energy Market 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 dynamically scheduled to load outside such area pursuant to Section 1.12.

Deviations that occur within a single Zone shall be associated with the Eastern or Western Regions, as defined in Section 3.2.3(q) of this Schedule, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with Section 3.2.3(q). Deviations at interfaces and hubs shall be associated with the Eastern or Western Region if all the busses that define all interfaces or all hubs are located in the region. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to 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 busses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed 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 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 an Operating Reserve shortage in real-time or where PJM initiates the request for load reductions in real-time in order to avoid an Operating Reserve shortage as described in this Schedule, Section 6A, Scarcity Pricing.

(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.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized 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 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 for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for of the PJM Region.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized 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 (net of operating Behind The Meter Generation, but not to be less than zero) 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 dynamically scheduled to load outside the PJM Region pursuant to 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 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 Schedule 2 of the Operating Agreement, 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 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 Section 1.9.7(b); provided, however, that the Market Seller must return to compliance with 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, the Market Seller shall not receive any credit for Operating Reserves. 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 for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatt hours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours 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 hours 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 12:00 noon 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 not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon 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 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 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 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 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 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 generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described in the PJM Manuals. Ramp-limited desired MW values shall be used to determine generation resource real-time deviations from the resource's day-ahead schedules.

The Office of the Interconnection shall calculate a ramp-limited desired MW value for 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:

$$Ramp\_Request_t = \frac{(UDStarget_{t-1} - AOutput_{t-1})}{(UDSLAtime_{t-1})}$$

$$RL\_Desired_t = AOutput_{t-1} + \left(Ramp\_Request_t * Case\_Eff\_time_{t-1}\right)$$

where:

1. UDStarget = UDS basepoint for the previous UDS case
2. AOutput = Unit's output at case solution time
3. UDSLAtime = UDS look ahead time
4. Case_Eff_time = Time between base point changes
5. RL_Desired = Ramp-limited desired MW

To determine if a 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 UDS Basepoint or the actual output and ramp-limited desired MW value. The % off dispatch and MW off dispatch will be a time-weighted average over the course of an hour. If the UDS Basepoint 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 UDS LMP Desired MW.

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 UDS Basepoint, or if its % off dispatch is <= 10, or it's hourly integrated Real-time MWh is within 5% or 5 MW (whichever is greater) of the hourly integrated 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 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: hourly integrated Real-time 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: hourly integrated Real-time MWh – UDS LMP Desired MW.

- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – hourly integrated 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 UDS LMP Desired MWh for the hour 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: hourly integrated Real time MWh – UDS 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: hourly integrated Real-time Mwh – hourly integrated Ramp-Limited Desired MW. If deviation value is within 5% or 5 MW (whichever is greater) 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: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch, and the resource has tripped, for the hour the resource tripped and the hours it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time 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: hourly integrated Real-time MWh and Day-Ahead MWh.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve 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 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 Operating Reserve charges shall be allocated to real-time deviations 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 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 Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing 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 Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed 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 charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category 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(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) 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 Region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, *DEOK* transmission Zones, and the Eastern 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:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve 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 reliability 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 Section 3.2.3(p).

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. 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 Section 3.2.3(p).

(iii) Reliability and deviation regional balancing Operating Reserve rates shall be determined by summing the relevant RTO balancing Operating Reserve 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.

3.2.3A Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Synchronized Reserve Zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Synchronized Reserve 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). An Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts if any, described in subsections (g), (h) and (i) of this section.

(b) A Generating Market Buyer supplying Synchronized Reserve at the direction of the Office of the Interconnection, in excess of its hourly Synchronized Reserve Obligation, shall be credited as follows:

i) Credits for Synchronized Reserve provided by generation units that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event ("Tier 1 Synchronized Reserve") shall be at the Synchronized Energy Premium Price.

ii) Credits for Synchronized Reserve provided by generation resources that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the Interconnection energy dispatch signals and instructions ("Tier 2 Synchronized Reserve") shall be the higher of (i) the Synchronized Reserve Market Clearing Price or (ii) the sum of (A) the Synchronized Reserve offer, and (B) the specific 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.

iii) Credits for Synchronized Reserve provided by Demand Resources that are synchronized to the grid and accept the obligation to reduce load in response to a synchronized Reserve Event initiated by the Office of the Interconnection shall be the sum of (i) the higher of (A) the Synchronized Reserve offer or (B) the synchronized Reserve Market Clearing Price and (ii) if a Synchronized Reserve Event is actually initiated by the Office of the Interconnection and the Demand Resource reduced its load in response to the event, the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

(c) The Synchronized Reserve Energy Premium Price is the average of the five-minute Locational Marginal Prices calculated during the Synchronized Reserve Event plus an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Synchronized Reserve Zone by the Office of the Interconnection prior to the operating hour and such market-clearing price shall be equal to, from among the generation resources or Demand Resources selected to provide Synchronized Reserve for such Synchronized Reserve Zone, the highest sum of either (i) a generation resource's Synchronized Reserve offer and opportunity cost or (ii) a demand response resource's Synchronized Reserve offer.

(e) In determining the Synchronized Reserve Market Clearing Price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the expected Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the difference between the expected 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 Synchronized Reserve set 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. The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to 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, times (B) 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 Synchronized Reserve set point for the generation 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. The opportunity costs for a Demand Resource shall be zero.

(g) Charges for Tier 1 Synchronized Reserve will be allocated in proportion to the amount of Tier 1 Synchronized Reserve applied to each Synchronized Reserve Obligation. In the event Tier 1 Synchronized Reserve is provided by a Market Seller in excess of that Market Seller's Synchronized Reserve Obligation, the remainder of the Tier 1 Synchronized Reserve that is not utilized to fulfill the Seller's obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

(h) Any amounts credited for Tier 2 Synchronized Reserve in an hour in excess of the Synchronized Reserve Market Clearing Price in that hour shall be allocated and charged to each Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation in proportion to its purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) In the event the Office of the Interconnection needs to assign more Tier 2 Synchronized Reserve during an hour than was estimated as needed at the time the Synchronized Reserve Market Clearing Price was calculated for that hour due to a reduction in available Tier 1 Synchronized Reserve, the costs of the excess Tier 2 Synchronized Reserve shall be allocated and charged to those providers of Tier 1 Synchronized Reserve whose available Tier 1 Synchronized Reserve was reduced from the needed amount estimated during the Synchronized Reserve Market Clearing Price calculation, in proportion to the amount of the reduction in Tier 1 Synchronized Reserve availability.

(j) In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled by the owner to provide Tier 2 Synchronized Reserve fails to provide the assigned or self-scheduled amount of Synchronized Reserve in response to an actual Synchronized Reserve Event, the owner of the resource shall incur an additional Synchronized Reserve Obligation in the amount of the shortfall for a period of three consecutive days with the same peak classification (on-peak or off-peak) as the day of the Synchronized Reserve Event at least three business days following the Synchronized Reserve Event. The overall Synchronized Reserve requirement for each Synchronized Reserve Zone of the PJM Region on which the Synchronized Reserve Obligations, except for the additional obligations set forth in this section, are based shall be reduced by the amount of this shortfall for the applicable three-day period.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l) is the difference between the generation resource's output or the Demand 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 Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand 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 a Demand Resource will be reduced by the amount the megawatt consumption of the Demand 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 Demand 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 Demand Resource's consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Demand 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.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJMSettlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

(b) A Day-ahead Scheduling Reserves Resource that receives a Day-ahead Scheduling Reserves schedule pursuant to subsection (a) of this section shall be paid the hourly Day-ahead Scheduling Reserves Market clearing price for the MW obligation in each hour of the schedule, subject to meeting the requirements of subsection (c) of this section.

(c) To be eligible for payment pursuant to subsection (b) of this section, Day-ahead Scheduling Reserves Resources shall comply with the following provisions:

(i) Generation resources with a start time greater than thirty minutes are required to be synchronized and operating at the direction of the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule and shall have a dispatchable range equal to or greater than the Day-ahead Scheduling Reserves schedule.

(ii) Generation resources and Demand Resources with start times or shut-down times, respectively, equal to or less than 30 minutes are required to respond to dispatch directives from the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule. To meet this requirement the resource shall be required to start or shut down within the specified notification time plus its start or shut down time, provided that such time shall be less than thirty minutes.

(iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). 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 one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand 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 time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand 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 credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

Resources that do not comply with the provisions of this subsection (c) shall not be eligible to receive credits pursuant to subsection (b) of this section.

(d) The cost of credits allocated to Day-ahead Scheduling Reserves Resources pursuant to this section shall be charged to Load-Serving Entities in the PJM Region based on load ratio share (net of operating Behind The Meter Generation, but not to be less than zero), provided that a Load-Serving Entity may satisfy its Day-ahead Scheduling Reserves obligation, which is equal to the Day-ahead Scheduling Reserves Requirement multiplied by the Load-Serving Entity's load ratio share for the PJM Region, through one or any combination of the following: 1) the Day-ahead Scheduling Reserves Market; 2) and bilateral arrangements. The Day-ahead Scheduling Reserve charges allocated pursuant to this section shall reflect any portion of a Load-Serving Entity's Day-ahead Scheduling Reserves obligation that is met by bilateral arrangement(s).

(e) If the Day-ahead Scheduling Reserves Requirement is not satisfied through the operation of subsection (a) of this section, any additional Operating Reserves required to meet the requirement shall be scheduled by the Office of the Interconnection pursuant to Section 3.2.3 of Schedule 1 of this Agreement.

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 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 either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, 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 hourly in an amount equal to {(LMPDMW - AG) x (URTLMP - UB)}

where:

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 hourly integrated real time LMP;

AG equals the actual hourly integrated output of the unit;

URTLMP equals the real time LMP at the unit's bus;

UB equals the unit offer for that unit for which output is reduced or suspended determined according to the real time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UB shall not be negative.

(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 Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost 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 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.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG, or (ii) {(URTLMP – UB) x DAG where:

URTLMP equals the real time LMP at the unit's bus;

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

(e) At the end of each Operating Day, where the active energy 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).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is 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 hourly in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual hourly integrated output of the unit;

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 hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

UB equals the unit offer for that unit for which output is increased, determined according to the real time scheduled offer curve on which the unit was operating;

URTLMP equals the real time LMP at the unit's bus; and

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to 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, 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 lost 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 lost 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 alternate lost 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 Tier 2 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 hourly Synchronized Reserve Market Clearing Price for each hour 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 generating unit's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generating unit's bus, (C) the

generating unit's startup-cost of providing synchronous condensing, and (D) 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 paragraph (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 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. 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 (net of operating Behind The Meter Generation) 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 PJM 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 Tier 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 hourly Synchronized Reserve Market Clearing Price for each hour 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 generation resource's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) 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 section (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 (net of operating Behind The Meter Generation) 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 Section 5 of this Schedule.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Section 5 of this Schedule.

3.2.6 Emergency Energy.

(a) 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 hour of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange 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.

(b) 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 hour of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net PJM Interchange 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.

(c) The net costs or net revenues associated with sales or purchases of hourly energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each hour 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 PJM Interchange 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 Buyer in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market Buyer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Buyer's internal accounting.

(b) If deliveries to a Market Buyer that has PJM Interchange meters in accordance with Section 14 of the Operating Agreement include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market Buyer, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market Buyer and the unmetered Market Participant specified by them to the Office of the Interconnection.

3.3 Market Sellers.

Except as provided in the following sentence, the accounting and billing principles and procedures applicable to Generating Market Buyers functioning as Market Sellers shall be as set forth in Section 3.2. This Section sets forth the accounting and billing principles and procedures applicable to all other Market Sellers, and to Generating Market Buyers functioning as Market Sellers with respect to any matters not specified in Section 3.2.

3.3.1 Spot Market Energy Charges.

(a) Market Sellers shall be paid for all energy scheduled to be delivered in the Day-ahead Energy Market at the Day-ahead System Energy Prices.

(b) At the end of each hour during an Operating Day, the Office of the Interconnection shall determine the total net amount of energy delivered in the hour to the PJM Region by each of the Market Seller's resources, in accordance with the PJM Manuals and the calculation described in Section 3.2.1(f).

(c) The Office of the Interconnection shall calculate Day-ahead and Real-time System Energy Prices for the PJM Region, in accordance with Section 2 of this Schedule.

(d) A Market Seller shall be paid for real-time sales of Spot Market Energy to the extent of its hourly net deliveries to the PJM Region of energy in excess of amounts scheduled in the Day-ahead Energy Market from the Market Seller's resources. For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the hourly amounts delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region. The total real-time generation revenues for each Market Seller shall be the sum of its payments determined by the product of (i) the hourly net amount of energy delivered to the PJM Region in excess of the amount scheduled to be delivered in that hour in the Day-ahead Energy Market from each of the Market Seller's resources, times (ii) the hourly Real-time System Energy Price. To the extent that the energy actually injected in any hour is less than the energy scheduled to be injected in the Day-ahead Energy Market, the Market Seller shall be debited for the difference at the Real-time System Energy Price at the time of the shortfall times the amount of the shortfall. The total generation revenue for each Market Seller shall be the sum, of the revenues at Day-ahead System Energy Prices determined in accordance with the Day-ahead Energy Market as specified in Section 3.3.1(a) plus the revenues at Real-time System Energy Prices determined as specified herein, net of any debits specified herein for each Market Seller.

3.3.2 Regulation.

Each Market Seller that is also an Internal Market Buyer as to load in a Regulation Zone shall have an hourly Regulation objective and shall be credited or charged in connection therewith as specified in Section 3.2.2. All other Market Sellers supplying Regulation in such Regulation Zone at the direction of the Office of the Interconnection shall be credited for each increment of

such Regulation at the price specified in Section 3.2.2(b), as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

3.3.3 Operating Reserves.

A Market Seller shall be credited for its pool-scheduled resources based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource, in accordance with the procedures set forth in Section 3.2.3.

3.3.4 Emergency Energy.

The net costs or net revenues associated with purchases or sales of energy in connection with Emergencies in the PJM Region, or in another Control Area, shall be allocated to Market Participants in accordance with the procedures set forth in Section 3.2.6.

3.3.5 Synchronized Reserve.

Each Market Seller that is also an Internal Market Buyer shall have an hourly Synchronized Reserve objective and shall be credited or charged in connection therewith as specified in Section 3.2.3A(a). All other Market Sellers supplying Synchronized Reserve at the direction of the Office of the Interconnection shall be credited for each increment of such Synchronized Reserve at the price specified in Section 3.2.3A(b), as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

3.3.6 Billing.

PJMSettlement shall prepare a billing statement each billing cycle for each Market Seller in accordance with the charges and credits specified in Sections 3.3.1 through 3.3.5 of this Schedule, and showing the net amount to be paid or received by the Market Seller. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Seller's internal accounting.

5.1 Transmission Congestion Charge Calculation.

5.1.1 Calculation by Office of the Interconnection.

When the transmission system is operating under constrained conditions, or as necessary to provide third-party transmission provider losses, the Office of the Interconnection shall calculate Transmission Congestion Charges for each Network Service User, Market Participants in the PJM Interchange Energy Market, and each Transmission Customer.

5.1.2 General.

The Office of the Interconnection shall calculate Congestion Prices in the form of Day-ahead Congestion Prices and Real-time Congestion Prices for the PJM Region, in accordance with Section 2 of this Schedule.

5.1.3 Network Service User Calculation.

(a) Each Network Service User shall be charged for the increased cost of energy incurred by it during each constrained hour to deliver the output of its firm Generation Capacity Resources or other owned or contracted for resources, its firm bilateral purchases, and its non-firm bilateral purchases as to which it has elected to pay Transmission Congestion Charges.

(b) Market Buyers shall be charged for transmission congestion resulting from all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy market in the Day-ahead Energy Market at the Day-ahead Congestion prices applicable to each relevant load bus.

(c) Generating Market Buyers shall be reimbursed for transmission congestion resulting from all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant generation bus.

(d) Market Sellers shall be reimbursed for transmission congestion resulting from all energy scheduled to be delivered in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant generation bus.

(e) The hourly net amount of energy delivered at each generation bus is determined by revenue meter data if available, or by the State Estimator, if revenue meter data is not available. The total load actually served at each load bus is initially determined by the State Estimator. For each Electric Distributor that reports hourly net energy flows from metered tie lines and for which all generators within the Electric Distributor's territory report revenue quality, hourly net energy delivered, the total revenue meter load within the Electric Distributor's territory is calculated as the sum of all net import energy flows reported by their tie revenue meters and all net generation reported via generator revenue meters. The amount of load at each of such Electric Distributor's load buses calculated by the State Estimator is then adjusted, in proportion to its share of the total load of that Electric Distributor, in order that the total amount

of load across all of the Electric Distributor's load buses matches its total revenue meter calculated load.

(f) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the Transmission Congestion Charges at each Market Buyer's load bus to be charged for congestion at Real-time Congestion Prices determined by the product of the hourly Real-time Congestion Price at the relevant bus times the Market Buyer's megawatts of load (net of operating Behind The Meter Generation, but not to be less than zero) at the bus in that hour in excess of the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the hour in the Day-ahead Energy Market. To the extent that the load (net of operating Behind The Meter Generation, but not to be less than zero) actually served at a load bus is less than the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the Day-ahead Energy Market, the Market Buyer shall be paid for the difference at the Real-time Congestion Price for the load bus at the time of the shortfall. The megawatts of load at each load bus shall be the sum of the megawatts of load (net of operating Behind The Meter Generation, but not less than zero) for that bus of that Market Buyer plus any megawatts of that Market Buyer's bilateral sales attributable to that bus. The total load charge for each Market Buyer shall be the sum, for each of a Market Buyer's load buses, of the charges at Day-ahead Congestion Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1a plus the charges at Real-time Congestion Prices determined as specified herein, net of any payments specified herein for each of the Market Buyer's load buses.

(g) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the transmission congestion payments at each Generating Market Buyer's generation bus to be paid at Real-time Congestion Prices, determined by the product of the hourly Real-time Congestion Price at the relevant bus times the Generating Market Buyer's megawatts of generation at such generation bus in the hour in excess of the energy scheduled to be injected at that bus in that hour in the Day-ahead Energy Market. To the extent that the energy actually injected at the generation bus is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Generating Market Buyer shall be debited for the difference at the Real-time Congestion Price for the generation bus at the time of the shortfall. The megawatts of generation at each generation bus shall be the sum of the megawatts of generation for that bus of that Generating Market Buyer plus any megawatts of bilateral purchases of that Generating Market Buyer attributable to that bus. The total generation revenue for each Generating Market Buyer shall be the sum, for each of the Generating Market Buyer's generation buses, of the revenues at Day-ahead Congestion Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Congestion Prices determined as specified herein, net of any debits specified herein for each of the Market Buyer's generation buses.

(h) A Market Seller shall be paid for transmission congestion that results from the Real-time sales of energy to the extent of its hourly net deliveries to the PJM Region of energy in excess of amounts scheduled in the Day-ahead Energy Market from the Market Seller's resources. For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the hourly amounts delivered from each such resource to the

corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region. The total real-time generation revenues for each Market Seller shall be the sum of its credits determined by the product of (i) the hourly net amount of energy delivered to the PJM Region at the applicable generation or interface bus in excess of the amount scheduled to be delivered in that hour at that bus in the Day-ahead Energy Market from each of the Market Seller's resources, times (ii) the hourly Real-time Congestion Price at that bus. To the extent that the energy actually injected at a generation or interface bus in any hour is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Market Seller shall be debited for the difference at the Real-time Congestion Price for the applicable bus at the time of the shortfall times the amount of the shortfall. The total generation revenue for each Market Seller shall be the sum, for each of the Market Seller's generation buses or Interface Pricing Points, of the revenues at Day-ahead Congestion Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Congestion Prices determined as specified herein, net of any debits specified herein for each of the Market Seller's generation or interface buses.

5.1.4 Transmission Customer Calculation.

Each Transmission Customer using Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), each Network Customer, and each Transmission Customer using Non-Firm Point-to-Point Transmission Service (as defined in the PJM Tariff) that has elected to pay Transmission Congestion Charges, shall be charged for the increased cost of energy during constrained hours for the delivery of energy using such Transmission Service. Except as specified in this subsection, a Transmission Congestion Charge shall be assessed for transmission use scheduled in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region and the Day-ahead Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. Transmission Congestion Charges shall be assessed for real-time transmission use in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. A Transmission Customer shall be paid for Transmission Congestion Charges for real-time transmission use falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region.

5.1.4A Transaction Calculation.

Each Market Participant entering into transactions in the PJM Interchange Energy Markets shall be charged for the increased cost of energy during constrained hours for the delivery of energy on the scheduled path. Except as specified in this subsection, a Transmission Congestion Charge shall be assessed for cleared MWh in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Congestion Price at the sink

point and the Day-ahead Congestion Price at the source point. Transmission Congestion Charges shall be assessed for real-time cleared MWh in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Congestion Price at the sink point and the Real-time Congestion Price at the source point. Such Market Participant shall be paid for Transmission Congestion Charges for real-time cleared MWh falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Congestion Price at the sink point and the Real-time Congestion Price at the source point.

5.1.5 Operating Margin Customer Calculation.

Each Control Area purchasing Operating Margin shall be assessed Transmission Congestion Charges for any increase in the cost of energy resulting from the provision of Operating Margin. The Transmission Congestion Charge shall be the amount of Operating Margin purchased in an hour multiplied by the difference in the Locational Marginal Price at what would be the delivery Interface Pricing Point and the Locational Marginal Price at what would be the source Interface Pricing Point, if the operating contingency that was the basis for the purchase of Operating Margin had occurred in that hour. Operating Margin may be allocated among multiple source and delivery Interface Pricing Points in accordance with an applicable load flow study.

5.1.6 Transmission Loading Relief Customer Calculation.

(a) Each Transmission Loading Relief Customer shall be assessed Transmission Congestion Charges for any increase in the cost of energy in the PJM Region resulting from its energy schedules over contract paths outside the PJM Region during Transmission Loading Relief.

(b) The Transmission Congestion Charge shall be the total amount of energy specified in such energy schedules multiplied by the difference between a Locational Marginal Price calculated by the Office of the Interconnection for the energy schedule source location specified in the NERC Interchange Distribution Calculator and a Locational Marginal Price calculated by the Office of the Interconnection for the energy schedule sink location specified in the NERC Interchange Distribution Calculator. Transmission Congestion Charges that are less than zero shall be set equal to zero for Transmission Loading Relief Customers.

(c) The Office of the Interconnection will determine the Locational Marginal Prices at the energy schedule source and sink locations external to PJM with reference to and based solely on the prices of energy in the PJM Region and at the Interface Pricing Points between adjacent Control Areas and the PJM Region and the system conditions and actual power flow distributions as described by the PJM State Estimator program. The Office of the Interconnection will determine the Locational Marginal Prices at the external energy schedule source and sink locations and the resulting Congestion Charge based on the portion of the energy schedule that flows through the PJM Region as reflected by the flow distributions from the PJM State Estimator program.

5.1.7 Total Transmission Congestion Charges.

The total Transmission Congestion Charges collected by PJMSettlement each hour will be the aggregate net amounts determined as specified in the PJM Manuals. PJMSettlement shall collect Transmission Congestion Charges for each hour the transmission system operates under constrained conditions.

5.4 Transmission Loss Charge Calculation.

5.4.1 Calculation by Office of the Interconnection.

The Office of the Interconnection shall calculate Transmission Loss Charges for each Network Service User, Market Participant in the PJM Interchange Energy Market, and each Transmission Customer.

5.4.2 General.

(a) The basis for the Transmission Loss Charges shall be the differences in the Locational Marginal Prices, defined as the Loss Price at a bus, between points of delivery and points of receipt, as determined in accordance with Section 2 of this Schedule. (b) The Office of the Interconnection shall calculate Loss Prices in the form of Day-ahead Loss Prices and Real-time Loss Prices for the PJM Region, in accordance with Section 2 of this Schedule.

5.4.3 Network Service User Calculation.

(a) Each Network Service User shall be charged for the increased cost of transmission losses to deliver the output of its firm Capacity Resources or other owned or contracted for resources, its firm bilateral purchases, and its non-firm bilateral purchases.

(b) Market Buyers shall be charged for transmission losses resulting from all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead Loss Price applicable to each relevant load bus.

(c) Generating Market Buyers shall be reimbursed for transmission losses resulting from all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead Loss Price applicable to each relevant generation bus.

(d) Market Sellers shall be reimbursed for transmission losses resulting from all energy scheduled to be delivered in the Day-ahead Energy Market at the Day-ahead Loss Prices applicable to each relevant generation bus.

(e) The hourly net amount of energy delivered at each generation bus is determined by revenue meter data, if available, or by the State Estimator, if revenue meter data is not available. The total load actually served at each load bus is initially determined by the State Estimator. For each Electric Distributor that reports hourly net energy flows from metered tie lines and for which all generators within the Electric Distributor's territory report revenue quality, hourly net energy delivered, the total revenue meter load within the Electric Distributor's territory is calculated as the sum of all net import energy flows reported by their tie revenue meters and all net generation reported via generator revenue meters. The amount of load at each of such Electric Distributor's load buses calculated by the State Estimator is then adjusted, in proportion to its share of the total load of that Electric Distributor, in order that the total amount

of load across all of the Electric Distributor's load buses matches its total revenue meter calculated load.

(f) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the Transmission Loss Charges at each Market Buyer's load bus to be charged for losses at Real-time Loss Prices determined by the product of the hourly Real-time Loss Prices at the relevant bus times the Market Buyer's megawatts of load (net of operating Behind The Meter Generation, but not to be less than zero) at the bus in that hour in excess of the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the hour in the Day-ahead Energy Market. To the extent that the load (net of operating Behind The Meter Generation, but not to be less than zero) actually served at a load bus is less than the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the Day-ahead Energy Market, the Market Buyer shall be paid for the difference at the Real-time Loss Price for the load bus at the time of the shortfall. The megawatts of load at each load bus shall be the sum of the megawatts of load (net of operating Behind The Meter Generation, but not less than zero) for that bus of that Market Buyer plus any megawatts of that Market Buyer's bilateral sales attributable to that bus. The total load charge for each Market Buyer shall be the sum, for each of a Market Buyer's load buses, of the charges at Day-ahead Loss Price determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1a plus the charges at Real-time Loss Prices determined as specified herein, net of any payments specified herein for each of the Market Buyer's load buses.

(g) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the transmission loss payments at each Generating Market Buyer's generation bus to be paid at Real-time Loss Prices, determined by the product of the hourly Real-time Loss Price at the relevant bus times the Generating Market Buyer's megawatts of generation at such generation bus in the hour in excess of the energy scheduled to be injected at that bus in that hour in the Day-ahead Energy Market. To the extent that the energy actually injected at the generation bus is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Generating Market Buyer shall be debited for the difference at the Real-time Loss Price for the generation bus at the time of the shortfall. The megawatts of generation at each generation bus shall be the sum of the megawatts of generation for that bus of that Generating Market Buyer plus any megawatts of bilateral purchases of that Generating Market Buyer attributable to that bus. The total generation revenue for each Generating Market Buyer shall be the sum, for each of the Generating Market Buyer's generation buses, of the revenues at Day-ahead Loss Price determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Loss Prices determined as specified herein, net of any debits specified herein for each of the Market Buyer's generation buses.

(h) A Market Seller shall be paid for transmission losses that results from the Real-time sales of Spot Market Energy to the extent of its hourly net deliveries to the PJM Region of energy in excess of amounts scheduled in the Day-ahead Energy Market from the Market Seller's resources. For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the hourly amounts delivered from each such resource to

the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region. The total real-time generation revenues for each Market Seller shall be the sum of its credits determined by the product of (i) the hourly net amount of energy delivered to the PJM Region at the applicable generation or interface bus in excess of the amount scheduled to be delivered in that hour at that bus in the Day-ahead Energy Market from each of the Market Seller's resources, times (ii) the hourly Real-time Loss Price at that bus. To the extent that the energy actually injected at a generation bus or Interface Pricing Point in any hour is less than the energy scheduled to be injected at that bus or point in the Day-ahead Energy Market, the Market Seller shall be debited for the difference at the Real-time Loss Price for the applicable bus or point at the time of the shortfall times the amount of the shortfall. The total generation revenue for each Market Seller shall be the sum, for each of the Market Seller's generation buses or Interface Pricing Points, of the revenues at Day-ahead Loss Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Loss Prices determined as specified herein, net of any debits specified herein for each of the Market Seller's generation buses or Interface Pricing Points.

5.4.4 Transmission Customer Calculation.

Each Transmission Customer using Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), each Network Customer, and each Transmission Customer using Non-Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), shall be charged for the increased cost of transmission losses for the delivery of energy using such Transmission Service. Except as specified in this subsection, a Transmission Loss Charge shall be assessed for transmission use scheduled in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Loss Price at the delivery point or the delivery interface at the boundary of the PJM Region and the Day-ahead Loss Price at the source point or the source interface at the boundary of the PJM Region. Transmission Loss Charges shall be assessed for real-time transmission use in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Loss Price at the delivery point or the delivery interface at the boundary of the PJM Region, and the Real-time Loss Price at the source point or the source interface at the boundary of the PJM Region. A Transmission Customer shall be paid for Transmission Loss Charges for real-time transmission use falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Loss Price at the delivery point or the delivery interface at the boundary of the PJM Region, and the Real-time Loss Price at the source point or the source interface at the boundary of the PJM Region or the source Interface Pricing Point at the boundary of the PJM Region.

5.4.4A Transaction Calculation.

Each Market Participant entering into transactions in the PJM Interchange Energy Market shall be charged for the increased cost of transmission losses on the scheduled path. Except as specified in this subsection, a Transmission Loss Charge shall be assessed for cleared MWh in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Loss Price at the sink point and the Day-ahead Loss Price at

the source point. Transmission Loss Charges shall be assessed for real-time cleared MWh in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Loss Price at the sink point and the real-time Loss Price at the source point. Such Market Participant shall be paid for Transmission Loss Charges for real-time cleared MWh falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Loss Price at the sink point and the Real-time Loss Price at the source point.

5.4.5 Total Transmission Loss Charges.

The total Transmission Loss Charges collected by PJMSettlement each hour will be the aggregate net amounts determined as specified in this Schedule.

ATTACHMENT M – APPENDIX

I. CONFIDENTIALITY OF DATA AND INFORMATION

A. Party Access:

1. 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 Market Monitoring Unit, to the extent such documents, data or information have been designated as confidential pursuant to the procedures adopted by 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.

2. Except as may be provided in this Appendix, the Plan, the PJM Operating Agreement or in the PJM Tariff, the Market Monitoring Unit 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 Market Monitoring Unit or by such Member or entity applying for membership; provided that nothing contained herein shall prohibit the Market Monitoring Unit 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. The Market Monitoring Unit shall collect and use confidential information only in connection with its authority under this Appendix, the Plan, the PJM Operating Agreement or in the PJM Tariff and the retention of such information shall be in accordance with PJM's data retention policies.

3. Nothing contained herein shall prevent the Market Monitoring Unit from releasing a Member's confidential data or information to a third party provided that the Member has delivered to 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 Market Monitoring Unit 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 Market Monitoring Unit, who shall cease such release as soon as practicable after receipt of such withdrawal notice.

4. Reciprocal provisions to this Section I hereof, delineating the confidentiality requirements of the Office of the Interconnection and PJM members, are set forth in Section 18.17 of the PJM Operating Agreement.

B. Required Disclosure:

1. Notwithstanding anything in the foregoing section to the contrary, and subject to the provisions of Section I.C below, if the Market Monitoring Unit is required by applicable law, 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 the PJM Tariff, PJM Operating Agreement, Attachment M or this Appendix, the Market Monitoring Unit may make disclosure of such information; provided, however, that as soon as the Market Monitoring Unit learns of the disclosure requirement and prior to making disclosure, the Market Monitoring Unit 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 Market Monitoring Unit shall cooperate with such affected Members to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. The Market Monitoring Unit 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.

2. Nothing in this Section I shall prohibit or otherwise limit the Market Monitoring Unit's use of information covered herein if such information was: (i) previously known to the Market Monitoring Unit without an obligation of confidentiality; (ii) independently developed by or for the Office of the Interconnection and/or the PJM Market Monitor using non-confidential information; (iii) acquired by the Office of the Interconnection and/or the PJM Market Monitor from a third party which is not, to the Office of the Market Monitoring Unit'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 I.

3. The Market Monitoring Unit shall impose on any contractors retained to provide technical support or otherwise to assist with the implementation of the Plan or this Appendix a contractual duty of confidentiality consistent with the Plan or this Appendix. 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 Market Monitoring Unit shall not provide any such information to any such contractor without the express written permission of the Member providing the information.

C. <u>Disclosure to FERC</u>:

1. Notwithstanding anything in this Section I to the contrary, if the FERC or its staff, during the course of an investigation or otherwise, requests information from the Market Monitoring Unit that is otherwise required to be maintained in confidence pursuant to the PJM Tariff, the PJM Operating Agreement, the Plan or this Appendix, the Market Monitoring Unit shall provide the requested information to the FERC or its staff, within the time provided for in the request for information. In providing the information to the FERC or its staff, the Market Monitoring Unit may, consistent with 18 C.F.R. § 388.112, request that the information be treated as confidential and non-public by the FERC and its staff and that the information be withheld from public disclosure. The Market Monitoring Unit shall notify any affected Member(s) when it is notified by FERC or its staff, that a request for disclosure of, or decision to disclose, confidential information has been received, at which time the Office of the Interconnection, the Market Monitoring Unit, and/or the affected Member may respond before such information would be made public, pursuant to 18 C.F.R. § 388.112.

2. The foregoing Section I.C.1 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, PJM and/or the Market Monitoring Unit shall follow the procedures in Section 18.17.2.

D. Disclosure to Authorized Commissions:

1. Notwithstanding anything in this Section I to the contrary, the Market Monitoring Unit shall disclose confidential information, otherwise required to be maintained in confidence pursuant to the PJM Tariff, the PJM Operating Agreement, the Plan or this Appendix, 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 to the PJM Operating Agreement as 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 FERC 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 protest proceeding. If there are material changes in law that affect the accuracy and adequacy of the representations in the Certification filed with the FERC, 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 FERC as set forth above in this paragraph.

(ii) Neither the Office of the Interconnection nor the Market Monitoring Unit may disclose data to an Authorized Commission during the FERC's consideration of the Certification and any filed protests. If the FERC 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 I. In the event that an interested party protests the Authorized Commission's Certification and the FERC 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.

(iii) Any confidential information provided to an Authorized Commission pursuant to this Section I shall not be further disclosed by the recipient Authorized Commission except by order of the FERC.

(iv) The Market Monitoring Unit 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.

(v) The Authorized Commission may provide confidential information obtained from the Market Monitoring Unit 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 nondisclosure agreement in the form attached to the PJM Operating Agreement as Schedule 10 before being provided access to any such confidential information.

2. The Market Monitoring Unit 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 Market Monitoring Unit will not make any written or electronic disclosures of confidential information to the Authorized Person pursuant to this Section I.D.2. In any such discussions, the Market Monitoring Unit 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 Market Monitoring Unit shall also be authorized to assist Authorized Persons in interpreting confidential information that is disclosed. The Market Monitoring Unit 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.

3. 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 Market Monitoring Unit, 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 Market Monitoring Unit 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 I.D.3(iii) below, the Market Monitoring Unit 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 Market Monitoring Unit 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 Market Monitoring Unit 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 Market Monitoring Unit shall not reveal any Member's confidential information to any other Member.

(iii) Notwithstanding Section I.D.3(ii), above, should the Office of the Interconnection, the Market Monitoring Unit or an Affected Member object to an Information Request or any portion thereof, any of them may, within four (4) business days following the Market Monitoring Unit'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, Market Monitoring Unit, or the Affected Member may file a complaint with the FERC 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 the 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 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 and/or Market Monitoring Unit 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 Market Monitoring Unit shall use its best efforts to respond to the Information Request promptly.

(iv) Any Authorized Commission may initiate appropriate legal action at the 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).

4. 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 Market Monitoring Unit, 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 I.

(ii) The Office Market Monitoring Unit shall terminate the right of such Authorized Commission to receive confidential information under this Section I 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 Market Monitoring Unit's actions under this Section I shall be to Commission. An Authorized Commission shall be entitled to reestablish its certification as set forth in Section I.D.1 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 recertification filing with sixty (60) days of the date of the filing, the recertification 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, the Market Monitoring Unit, and/or the Affected Member shall have the right to seek and obtain at least the following types of relief: (a) an order from the 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 Market Monitoring Unit.

(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 I.D.4(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 I.D.4(ii) or I.D.4(iii)(a) above, shall be submitted to the FERC for hearing and resolution. Any dispute or conflict requesting the relief in Section I.D.4(iii)(c) above may be submitted to FERC or any court of competent jurisdiction for hearing and resolution.

E. Market Monitoring:

1. Subject to the requirements of Section E.2, the Market Monitoring Unit may release confidential information of Public Service Electric & Gas Company ("PSE&G"), Consolidated Edison Company of New York ("ConEd"), and their affiliates, and the confidential information of any Member regarding generation and/or transmission facilities located within the PSE&G Zone to the New York Independent System Operator, Inc. ("New York ISO"), the market monitoring unit of New York ISO and the New York ISO Market Advisor to the limited extent that PJM or the Market Monitoring Unit determines necessary to carry out the responsibilities of PJM, New York ISO or the market monitoring units of PJM and the New York ISO under FERC Opinion No. 476 (see Consolidated Edison Company v. Public Service Electric and Gas Company, et al., 108 FERC ¶ 61,120, at P 215 (2004)) to conduct joint investigations to ensure that gaming, abuse of market power, or similar activities do not take place with regard to power transfers under the contracts that are the subject of FERC Opinion No. 476.

2. The Market Monitoring Unit may release a Member's confidential information pursuant to Section I.E.1 to the New York ISO, the market monitoring unit of the New York ISO and the New York ISO Market Advisor only if the New York ISO, the market monitoring unit of the New York ISO and the New York ISO Market Advisor are subject to obligations limiting the disclosure of such information that are equivalent to or greater than the limitations on disclosure specified in this Section I.E. Information received from the New York ISO, the market monitoring unit of the New York ISO, or the New York ISO Market Advisor under Section I.E.1 that is designated as confidential shall be protected from disclosure in accordance with this Section I.E.

II. DEVELOPMENT OF INPUTS FOR PROSPECTIVE MITIGATION

A. Offer Price Caps:

1. The Market Monitor or his designee shall advise the Office of the Interconnection whether it believes that the cost references, methods and rules included in the Cost Development Guidelines are accurate and appropriate, as specified in the PJM Manuals.

2. The Market Monitoring Unit shall review upon request of a Market Seller, and may review upon its own initiative at any time, the incremental costs (defined in Section 6.4.2 of Schedule 1of the Operating Agreement) included in the Offer Price Cap of a generating unit in order to ensure that the Market Seller has correctly applied the Cost Development Guidelines and that the level of the Offer Price Cap is otherwise acceptable.

3. The Market Monitoring Unit shall issue a written notice to a unit indicating that it is a "Frequently Mitigated Unit" or "FMU," or an "Associated Unit," when the Market Monitoring Unit determines that the unit meets the criteria delineated in Section 6.4.2 of Schedule 1 of the Operating Agreement.

4. Notwithstanding the number of jointly pivotal suppliers in any hour, if the Market Monitoring Unit determines that a reasonable level of competition will not exist based on an evaluation of all facts and circumstances, it may propose to the Commission the removal of offer-capping suspensions otherwise authorized by Section 6.4 of the Operating Agreement. Such proposals shall take effect upon Commission acceptance of the Market Monitoring Unit's filing.

B. <u>Minimum Generator Operating Parameters</u>:

1. The Market Monitoring Unit shall provide to the Office of the Interconnection a table of default unit class specific parameter limits to be known as the "Parameter Limited Schedule Matrix" to be included in Section 6.6(c) of Schedule 1 of the Operating Agreement. The Parameter Limited Schedule Matrix shall include default values on a unit-type basis as specified in Section 6.6(c). The Market Monitoring Unit shall review the Parameter Limited Schedule Matrix twice yearly, and, in the event it determines that revision is appropriate, shall provide a revised matrix to the Office of the Interconnection by no later than December 31 and June 30, respectively, prior to the bi-annual enrollment periods for the submission of start-up and no-load costs on April 1 and October 1.

2. The Market Monitoring Unit shall notify Generation Capacity Resources no later than March 15 and September 15 each year of its determination regarding each request for an exception to a value specified in the Parameter Limited Schedule Matrix or the parameters defined in Section 6.6 of Schedule 1 of the Operating Agreement and the PJM Manuals, provided that the Market Monitoring Unit receives such request by no later than February 28 or August 31, respectively. The Market Monitoring Unit's determination for an exception shall continue for a period of no less than six months, and, if requested, for such longer period as the Market Monitoring Unit may determine is supported by the data.

3. When a Generation Capacity Resource notifies the Market Monitoring Unit of a material change to the facts relied upon by the Market Monitoring Unit to support a parameter limited schedule exception pursuant to Section 6.7 of Schedule 1 of the Operating Agreement (or the Commission in support of its approval), the Market Monitoring Unit shall either agree to continue the existing exception, agree to a revised exception or find that no exception is supported by the data, in which case the values specified in the parameter limited schedule matrix shall apply.

4. The Market Monitoring Unit shall notify the Office of the Interconnection of any risk premium to which it and a nuclear generation resource agree or its determination if agreement is not obtained. If a nuclear generation resource submits a risk premium inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such risk premium, the Market Monitoring Unit may exercise its powers to inform Commission staff of its

concerns and request a determination that would require the nuclear generation resource to submit an appropriate risk premium.

C. RPM Must-Offer Obligation:

1. The Market Monitoring Unit shall maintain, post on its website and provide to the Office of the Interconnection prior to each RPM Auction (updated, as necessary, on at least a quarterly basis), a list of Existing Generation Capacity Resources located in the PJM Region that are subject to the "must-offer" obligation set forth in Section 6.6 of Attachment DD.

2. The Market Monitoring Unit shall evaluate requests submitted by Capacity Market Sellers for a determination that a Generation Capacity Resource, or any portion thereof, be removed from Capacity Resource status or exempted from status as a Generation Capacity Resource subject to Section II.C.1 above and inform both the Capacity Market Seller and the Office of the Interconnection of such determination. A Generation Capacity Resource located in the PJM Region shall not be removed from Capacity Resource status to the extent the resource is committed to service of PJM loads as a result of an RPM Auction, FRR Capacity Plan, Locational UCAP transaction and/or by designation as a replacement resource under this Attachment DD.

3. The Market Monitoring Unit shall evaluate the data and documentation provided to it by a potential Capacity Market Seller to establish the EFORd to be included in a Sell Offer applicable to each resource pursuant to Section 6.6 of Attachment DD, then it shall notify the Office of the Interconnection of any EFORd to which it and the Generation Capacity Resource agree or its determination of the EFORd if agreement is not obtained.

4. The Market Monitoring Unit shall consider the documentation provided to it by a potential Capacity Market Seller pursuant to Section 6.6 of Attachment DD, and determine whether a resource owned or controlled by such Capacity Market Seller meets the criteria to qualify for an exception to the must-offer requirement because the resource (i) is reasonably expected to be physically unable to participate in the relevant auction; (ii) has a financially and physically firm commitment to an external sale of its capacity; or (iii) was interconnected to the Transmission System as an Energy Resource and not subsequently converted to a Capacity Resource. The Market Monitoring Unit shall inform both the Capacity Market Seller and the Office of the Interconnection of its determination within ten (10) business days of its initial receipt of the documentation.

In order to establish that a resource is reasonably expected to be physically unable to participate in the relevant auction as set forth in (i) above, the Capacity Market Seller must demonstrate that:

A. It has a documented plan in place to retire the resource prior to or during the Delivery Year, and has submitted a notice of Deactivation to the Office of the Interconnection consistent with Section 113.1 of the PJM Tariff, without regard to whether the Office of the Interconnection has requested the Capacity Market Seller to continue to operate the resource beyond its desired deactivation date in accordance with Section 113.2 of the PJM Tariff for the

purpose of maintaining the reliability of the PJM Transmission System and the Capacity Market Seller has agreed to do so;

B. Significant physical operational restrictions cause long term or permanent changes to the installed capacity value of the resource, or the resource is under major repair that will extend into the applicable Delivery Year, that will result in the imposition of RPM performance penalties pursuant to Attachment DD of the PJM Tariff;

C. The Capacity Market Seller is involved in an ongoing regulatory proceeding (e.g. – regarding potential environmental restrictions) specific to the resource and has received an order, decision, final rule, opinion or other final directive from the regulatory authority that will result in the retirement of the resource; or,

D. A resource considered an Existing Generating Capacity Resource because it cleared an RPM Auction for a Delivery Year prior to the Delivery Year of the relevant auction, but which is not yet in service, is unable to achieve full commercial operation prior to the Delivery Year of the relevant auction. The Capacity Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer certifying that the resource will not be in full commercial operation prior to the referenced Delivery Year.

5. If a Capacity Market Seller submits for the portion of a Generation Capacity Resource that it owns or controls, and the Office of Interconnection accepts, a Sell Offer (i) at a level of installed capacity that the Market Monitoring Unit believes is inconsistent with the level established under Section 5.6.6 of Attachment DD of the PJM Tariff, (ii) at a level of installed capacity inconsistent with its determination of eligibility for an exception listed in Section II.C.4 above, or (iii) a maximum EFORd that the Market Monitoring Unit believes is inconsistent with the maximum level determined under Section II.C.3 of this Appendix, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and/or request a determination from the Commission that would require the Generation Capacity Resource to submit a new or revised Sell Offer, notwithstanding any determination to the contrary made under Section 6.6 of Attachment DD.

The Market Monitoring Unit shall also consider the documentation provided by the Capacity Market Seller pursuant to Section 6.6 of Attachment DD, for generation resources for which the Office of the Interconnection has not approved an exception to the must-offer requirement as set forth in Section 6.6(g) of Attachment DD, to determine whether the Capacity Market Seller's failure to offer part or all of one or more generation resources into an RPM Auction would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction as required by Section 6.6(i) of Attachment DD, and shall inform both the Capacity Market Seller and the Office of the Interconnection of its determination within ten (10) business days of its initial receipt of the documentation.

D. <u>Preliminary Market Structure Screen</u>:

1. In sufficient time to permit the posting required by Section 6.2(a) of Attachment DD, the Market Monitoring Unit shall apply the Preliminary Market Structure Screen to identify the

LDAs in which Capacity Market Sellers must provide the data specified in Section 6.7(b) of Attachment DD for any auction conducted with respect to such Delivery Year and whether Capacity Market Sellers must provide this data for the entire PJM Region. For each LDA and for the PJM Region, the Preliminary Market Structure Screen will be based on: (1) the Unforced Capacity available for such Delivery Year from Generation Capacity Resources located in such area; and (2) the Locational Deliverability Area Reliability Requirement and the PJM Reliability Requirement. For purposes of this screen, any LDA for which a separate Variable Resource Requirement Curve has not been established under Section 5.10 of Attachment DD shall be combined with all other such LDAs that form an electrically contiguous area ("Unconstrained LDA Group"), and the screen shall be applied to such area in the aggregate, rather than to each such LDA individually. Any such Unconstrained LDA Groups shall be identified in the posting required by Section 6.2(a) of Attachment DD.

2. An LDA, Unconstrained LDA Group, or the entire PJM Region shall fail the Preliminary Market Structure Screen, and Capacity Market Sellers owning or controlling any Generation Capacity Resource located in such LDA, Unconstrained LDA Group, or region shall be required to provide the information specified in Section 6.7 of Attachment DD, if any one of the following three conditions is met: (1) the market share of any Capacity Market Seller exceeds twenty percent; (2) the HHI for all such sellers is 1800 or higher; or (3) there are not more than three jointly pivotal suppliers.

3. By no later than 90 days prior to the conduct of the Base Residual Auction and each Incremental Auction for such Delivery Year, the Market Monitoring Unit shall provide to the Office of Interconnection and post or continue posting on its website for each LDA, Unconstrained LDA Group (if applicable) and to the entire PJM Region, the result of its Preliminary Market Structure Screen.

4. The Market Monitoring Unit shall not reflect in the Preliminary Market Structure Screen a firm external sale of capacity if a Capacity Market Seller has not met the requirements set forth in Section II.C.4(ii) above and Section 6.6 prior to the deadline for Capacity Market Sellers to submit data for such Preliminary Market Structure Screen, nor shall it reflect the removal of a resource (or portion thereof) from the Capacity Resource status list unless the associated unit-specific bilateral transaction is approved pursuant to subsection 5.6.6(c) or the designation of such resource (or portion thereof) as a network resource for the external load is demonstrated to the Office of the Interconnection.

5. The Preliminary Market Structure Screen shall reflect the removal of resources from PJM Capacity Resource status approved as provided under Section II.C.2 above no less than 30 days prior to the posting deadline.

E. <u>Market Seller Offer Caps</u>:

1. Based on the data and calculations submitted by the Capacity Market Sellers for each Existing Generation Capacity Resource and the formulas specified in Section 6.7(d) of Attachment DD, the Market Monitoring Unit shall calculate the Market Seller Offer Cap for each such resource, and notify the Capacity Market Seller one month prior to the auction of its determination. This provision is duplicated in Section 6.7(d) of Attachment DD.

2. The Market Monitoring Unit must attempt to reach agreement with the Capacity Market Seller on the level of the Market Seller Offer Cap. If such agreement cannot be reached because a Capacity Market Seller fails to submit data adequate to support the Market Seller Offer Cap requested, then the Market Monitoring Unit shall so inform the Office of the Interconnection. In the event that a Capacity Market Seller and the Market Monitoring Unit cannot come to agreement on the level of a Market Seller Offer Cap, then the Market Monitoring Unit shall inform the Capacity Market Seller and the Office of the Interconnection of its determination, and the Market Monitoring Unit may pursue any action available to it under Attachment M.

3. Nothing herein shall preclude any Capacity Market Seller and the Market Monitoring Unit from agreeing to, nor require either such entity to agree to, an alternative market seller offer cap determined on a mutually agreeable basis. Any such alternative offer cap shall be filed with the Commission for its approval. This provision is duplicated in Section 6.4(a) of Attachment DD.

F. Mitigation of Offers from Planned Generation Capacity Resources:

Pursuant to Section 6.5 of Attachment DD, the Market Monitoring Unit shall notify each Capacity Market Seller whose Sell Offer has been determined to be excessive.

G. Data Submission:

Pursuant to Section 6.7 of Attachment DD, the Market Monitoring Unit may request additional information from any potential auction participant as deemed necessary by the Market Monitoring Unit, including, without limitation, additional cost data on resources in a class that is not otherwise expected to include the marginal price setting resource; and compliance with such request shall be a condition of participation in any auction. All data submitted to the Office of the Interconnection or the Market Monitoring Unit by a Market Participant is subject to verification by the Market Monitoring Unit.

H. Determination of Avoidable Cost Rates:

1. The Market Monitoring Unit shall annually review the table of default Avoidable Cost Rates included in Section 6.7(c) of Attachment DD and calculated on the bases set forth therein, and determine whether the values included therein need to be updated. If so, the Market Monitoring Unit shall provide to the Office of the Interconnection updated values or notice of its determination that updated values are not needed.

2. The Market Monitoring Unit shall indicate in its posted reports on RPM performance the number of Generation Capacity Resources and megawatts per LDA that use the retirement Avoidable Cost Rates.

3. If a Capacity Market Seller does not elect to use a default Avoidable Cost Rate and has timely provided to the Market Monitoring Unit the data described in Section 6.7 of Attachment DD, the Market Monitoring Unit shall calculate the Avoidable Cost Rate (or may calculate, in

the case of the tardy receipt of data) and provide a unit-specific value to the Capacity Market Seller.

4. If a Capacity Market Sellers submits a retirement Avoidable Cost Rate that is higher than the applicable default Avoidable Cost Rate included in the table in Section 6.7 of Attachment DD, and the Capacity Market Seller and the Market Monitoring Unit do not agree that the proposed retirement Avoidable Cost Rate that has been submitted is appropriate, and the Office of the Interconnection accepts the proposed retirement Avoidable Cost Rate submitted by the Capacity Market Seller, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and request a determination that would require the Capacity Market Seller to utilize the retirement Avoidable Cost Rate determined by the Market Monitoring Unit or such other retirement Avoidable Cost Rate as determined by the Commission.

I. Determination of PJM Market Revenues:

The Market Monitoring Unit shall calculate the Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied pursuant to Section 6.8(d) of Attachment DD.

J. Determination of Opportunity Costs:

The Market Monitoring Unit shall review and verify the documentation of prices available to Existing Generation Capacity Resources in markets external to PJM and proposed for inclusion in Opportunity Costs pursuant to Section 6.7(d)(ii) of Attachment DD. The Market Monitoring Unit shall notify such Generation Capacity Resource and the Office of the Interconnection if it is dissatisfied with the documentation provided and whether it objects to the inclusion of such Opportunity Costs in a Market Seller Offer. If such Generation Capacity Resource submits a Market Seller Offer that includes Opportunity Costs that have not been documented and verified to the Market Monitoring Unit's satisfaction, then the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and request a determination that would require the Generation Capacity Resource to remove them.

III. BLACKSTART SERVICE

A. Upon the submission by a Black Start Service generator owner of a request for changes to the Black Start Service revenue requirements for the generator, the Black Start Service generator owner and the Market Monitoring Unit shall attempt to agree to values.

B. Pursuant to the terms of Schedule 6A of the PJM Tariff and the PJM Manuals, the Market Monitoring Unit will analyze any requested generator black start cost changes on an annual basis and shall notify the Office of the Interconnection of any costs to which it and the Black Start Service generator owner have agreed or the Market Monitoring Unit's determination regarding any cost components to which agreement has not been obtained. If a Black Start Service generator owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost component, and the Office of the Interconnection accepts the Black Start Service revenue requirements submitted by the Black

Start Service generator owner, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and request a determination that would require the Black Start Service generator to utilize the values determined by the Market Monitoring Unit or such other values as determined by the Commission.

IV. DEACTIVATION RATES

1. Upon receipt of a notice to deactivate a generating unit under Part V of the PJM Tariff from the Office of the Interconnection forwarded pursuant to Section 113.1 of the PJM Tariff, the Market Monitoring Unit shall analyze the effects of the proposed deactivation with regard to potential market power issues and shall notify the Office of the Interconnection and the generator owner (of, if applicable, its designated agent) within 30 days of the deactivation request if a market power issue has been identified. Such notice shall include the specific market power impact resulting from the proposed deactivation of the generating unit, as well as an initial assessment of any steps that could be taken to mitigate the market power impact.

2. The Market Monitoring Unit and the generating unit owner shall attempt to come to agreement on the level of each component included in the Deactivation Avoidable Cost Credit. In the case of cost of service filing submitted to the Commission in alternative to the Deactivation Cost Credit, the Market Monitoring Unit shall indicate to the generating unit owner in advance of filing its views regarding the proposed method or cost components of recovery. The Market Monitoring Unit shall notify the Office of the Interconnection of any costs to which it and the generating unit owner have agreed or the Market Monitoring Unit's determination regarding any cost components to which agreement has not been obtained. If a generating unit owner includes a cost component inconsistent with its agreement or inconsistent with the Market Monitoring Unit's determination regarding such cost components, the Market Monitoring Unit may exercise is powers to inform Commission staff of its concerns and seek a determination that would require the Generating unit to include an appropriate cost component. This provision is duplicated in Sections 114 and 119 of Part V of the PJM Tariff.

V. OPPORTUNITY COST CALCULATION

The Market Monitoring Unit shall review requests for opportunity cost compensation under Sections 3.2.3(f-3) and 3.2.3B(h) of Schedule 1 of the Operating Agreement, discuss with the Office of the Interconnection and individual Market Sellers the amount of compensation, and file exercise its powers to inform Commission staff of its concerns and request a determination of compensation as provided by such sections. These requirements are duplicated in Sections 3.2.3(f-3) and 3.2.3B(h) of Schedule 1 of the Operating Agreement.

VI. FTR FORFEITURE RULE

The Market Monitoring Unit shall calculate Transmission Congestion Credits as required under Section 5.2.1(b) of Schedule 1 of the Operating Agreement, including the determination of the identity of the holder of FTRs and an evaluation of the overall benefits accrued by an entity or affiliated entities trading in FTRs and virtual trading in the Day-ahead Energy Market, and provide such calculations to the Office of the Interconnection. Nothing in this section shall preclude the Market Monitoring Unit from action to recover inappropriate benefits from the

subject activity if the amount forfeited is less than the benefit derived by the FTR holder. If the Office of the Interconnection imposes a forfeiture of the Transmission Congestion Credit in an amount that the Market Monitoring Unit disagrees with, then it may exercise its powers to inform Commission staff of its concerns and request an adjustment.

VII. FORCED OUTAGE RULE

1. The Market Monitoring Unit shall observe offers submitted in the Day-ahead Energy Market to determine whether all or part of a generating unit's capacity (MW) is designated as Maximum Emergency and (i) such offer in the Real-time Energy Market designates a smaller amount of capacity from that unit as Maximum Emergency for the same time period, and (ii) there is no physical reason to designate a larger amount of capacity as Maximum Emergency in the offer in the Day-ahead Energy Market than in the Real-time Energy Market, the Market Monitoring Unit shall notify the Office of Interconnection.

2. If the Market Monitoring Unit observes that (i) an offer submitted in the Day-ahead Energy market designates all or part of capacity (MW) of a Generating unit as economic maximum that is less than the economic maximum designated in the offer in the Real-time Energy Market, and (ii) there is no physical reason to designate a lower economic maximum in the offer in the Day-ahead Energy Market than in the offer in the Real-time Energy Market, the Market Monitoring Unit shall notify the Office of Interconnection.

VIII. DATA COLLECTION AND VERIFICATION

The Market Monitoring Unit shall gather and keep confidential detailed data on the procurement and usage of fuel to produce electric power transmitted in the PJM Region in order to assist the performance of its duties under Attachment M. To achieve this objective, the Market Monitoring Unit shall maintain on its website a mechanism that allows Members to conveniently and confidentially submit such data and develop a manual in consultation with stakeholders that describes the nature of and procedure for collecting data. Members of PJM owning a Generating unit that is located in the PJM Region (including dynamically scheduled units), or is included in a PJM Black Start Service plan, committed as a Generation Capacity Resource for the current or future Delivery Year, or otherwise subject to a commitment to provide service to PJM, shall provide data to the Market Monitoring Unit.

2. DEFINITIONS

Definitions specific to this Attachment are set forth below. In addition, any capitalized terms used in this Attachment not defined herein shall have the meaning given to such terms elsewhere in this Tariff or in the RAA. References to section numbers in this Attachment DD refer to sections of this attachment, unless otherwise specified.

2.1A Annual Demand Resource

"Annual Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.1B Annual Resource

"Annual Resource" shall mean a Generation Capacity Resource, an Energy Efficiency Resource or an Annual Demand Resource.

2.1C Annual Resource Price Adder

"Annual Resource Price Adder" shall mean an addition to the marginal value of Unforced Capacity and the Extended Summer Resource Price Adder as necessary to reflect the price of Annual Resources required to meet the applicable Minimum Annual Resource Requirement.

2.1D Annual Revenue Rate

"Annual Revenue Rate" shall mean the rate employed to assess a compliance penalty charge on a Demand Resource Provider or ILR Provider under section 11.

2.2 Avoidable Cost Rate

"Avoidable Cost Rate" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.3 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.

2.4 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.

2.5 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.

2.6 Buy Bid

"Buy Bid" shall mean a bid to buy Capacity Resources in any Incremental Auction.

2.7 Capacity Credit

"Capacity Credit" shall have the meaning specified in Schedule 11 of the Operating Agreement, including Capacity Credits obtained prior to the termination of such Schedule applicable to periods after the termination of such Schedule.

2.8 Capacity Emergency Transfer Limit

"Capacity Emergency Transfer Limit" or "CETL" shall have the meaning provided in the Reliability Assurance Agreement.

2.9 Capacity Emergency Transfer Objective

"Capacity Emergency Transfer Objective" or "CETO" shall have the meaning provided in the Reliability Assurance Agreement.

2.9A Capacity Export Transmission Customer

"Capacity Export Transmission Customer" shall mean a customer taking point to point transmission service under Part II of this Tariff to export capacity from a generation resource located in the PJM Region that has qualified for an exception to the RPM must-offer requirement as described in section 6.6(g).

2.10 Capacity Market Buyer

"Capacity Market Buyer" shall mean a Member that submits bids to buy Capacity Resources in any Incremental Auction.

2.11 Capacity Market Seller

"Capacity Market Seller" shall mean a Member that owns, or has the contractual authority to control the output or load reduction capability of, a Capacity Resource, that has not transferred such authority to another entity, and that offers such resource in the Base Residual Auction or an Incremental Auction.

2.12 Capacity Resource

"Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.13 Capacity Resource Clearing Price

"Capacity Resource Clearing Price" shall mean the price calculated for a Capacity Resource that offered and cleared in a Base Residual Auction or Incremental Auction, in accordance with Section 5.

2.14 Capacity Transfer Right

"Capacity Transfer Right" shall mean a right, allocated to LSEs serving load in a Locational Deliverability Area, to receive payments, based on the transmission import capability into such Locational Deliverability Area, that offset, in whole or in part, the charges attributable to the Locational Price Adder, if any, included in the Zonal Capacity Price calculated for a Locational Delivery Area.

2.14A Conditional Incremental Auction

"Conditional Incremental Auction" shall mean an Incremental Auction conducted for a Delivery Year if and when necessary to secure commitments of additional capacity to address reliability criteria violations arising from the delay in a Backbone Transmission upgrade that was modeled in the Base Residual Auction for such Delivery Year.

2.15 CONE Area

"CONE Area" shall mean the areas listed in section 5.10(a)(iv)(A) and any LDAs established as CONE Areas pursuant to section 5.10(a)(iv)(B).

2.16 Cost of New Entry

"Cost of New Entry" or "CONE" shall mean the nominal levelized cost of a Reference Resource, as determined in accordance with section 5.

2.16A Credit-Limited Offer

"Credit-Limited Offer" shall have the meaning provided in Attachment Q to this Tariff.

2.17 Daily Deficiency Rate

"Daily Deficiency Rate" shall mean the rate employed to assess certain deficiency charges under sections 7, 8, 9, or 13.

2.18 Daily Unforced Capacity Obligation

"Daily Unforced Capacity Obligation" shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with Schedule 8 of the Reliability Assurance Agreement.

2.19 Delivery Year

Delivery Year shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Section 5.

2.20 Demand Resource

"Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.21 Demand Resource Factor

"Demand Resource Factor" shall have the meaning specified in the Reliability Assurance Agreement.

2.22 Demand Resource Provider

"Demand Resource Provider" shall mean a PJM Member that has the capability to reduce load, or that aggregates customers capable of reducing load. The Demand Resource Provider shall notify the Office of the Interconnection whether such load reduction is provided by a Limited Demand Resource, Extended Summer Demand Resource or an Annual Demand Resource. A Curtailment Service Provider, as defined in the Operating Agreement, may be a Demand Resource Provider, provided it qualifies its load reduction capability as a Limited Demand Resource, Extended Summer Demand Resource, or Annual Demand Resource.

2.23 EFORd

"EFORd" shall have the meaning specified in the PJM Reliability Assurance Agreement.

2.24 Energy Efficiency Resource

"Energy Efficiency Resource" shall have the meaning specified in the PJM Reliability Assurance Agreement.

2.24A Extended Summer Demand Resource

"Extended Summer Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.24B Extended Summer Resource Price Adder

"Extended Summer Resource Price Adder" shall mean an addition to the marginal value of Unforced Capacity as necessary to reflect the price of Annual Resources and Extended Summer Demand Resources required to meet the applicable Minimum Extended Summer Resource Requirement.

2.24C Extended Summer Demand Resource Reliability Target

"Extended Summer Demand Resource Reliability Target" for the PJM Region or an LDA, shall mean the maximum amount of the combination of Extended Summer Demand Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity, that shall be used to calculate the Minimum Annual Resource Requirement. As more fully set forth in the PJM Manuals, PJM calculates the Extended Summer DR Reliability Target, by first determining a reference annual loss of load expectation ("LOLE") assuming no Demand Resources. The calculation for the unconstrained portion of the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Capacity Emergency Transfer Objective study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of DR (displacing otherwise committed generation) as interruptible from May 1 through October 31 and unavailable from November 1 through April 30 and calculates the LOLE at each DR level. The Extended Summer DR Reliability Target is the DR amount, stated as a percentage of the unrestricted peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Extended Summer Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.25 [Reserved]

2.26 Final RTO Unforced Capacity Obligation

"Final RTO Unforced Capacity Obligation" shall mean the capacity obligation for the PJM Region, determined in accordance with Schedule 8 of the Reliability Assurance Agreement.

2.26A Final Zonal ILR Price

"Final Zonal ILR Price" shall mean the Adjusted Zonal Capacity Price after the Second Incremental Auction, less the amount paid in CTR credits per MW of load in the Zone in which the ILR is to be certified.

2.27 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.

2.28 Forecast Pool Requirement

"Forecast Pool Requirement" shall have the meaning specified in the Reliability Assurance Agreement.

2.29 Forecast RTO ILR Obligation

"Forecast RTO ILR Obligation" shall mean, in unforced capacity terms, the ILR Forecast for the PJM Region times the DR Factor, times the Forecast Pool Requirement, less the Unforced Capacity of all Demand Resources committed in FRR Capacity Plans by all FRR Entities in the PJM Region, for use in Delivery Years through May 31, 2012.

2.30 Forecast Zonal ILR Obligation

"Forecast Zonal ILR Obligation" shall mean, in unforced capacity terms, the ILR Forecast for the Zone times the DR Factor, times the Forecast Pool Requirement, less the Unforced Capacity of all Demand Resources committed in FRR Capacity Plans by all FRR Entities in such Zone, for use in Delivery Years through May 31, 2012.

2.31 Generation Capacity Resource

"Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.32 ILR Forecast

"ILR Forecast" shall mean, for any Delivery Year ending on or before May 31, 2012, the average annual megawatt quantity of ILR certified for the five Planning Periods preceding the date of the forecast; provided, however, that before such data becomes available for five Delivery Years under the Reliability Pricing Model, comparable data on Active Load Management (as defined in the preexisting reliability assurance agreements) from up to five prior Planning Periods shall be substituted as necessary; and provided further that, for transmission zones that were integrated into the PJM Region less than five years prior to the conduct of the Base Residual Auction for the Delivery Year, data on incremental load subject to mandatory interruption by Electric Distribution Companies within such zones shall be substituted as necessary.

2.33 ILR Provider

"ILR Provider" shall mean a Member that has the capability to reduce load, or that aggregates customers capable of reducing load. A Curtailment Service Provider, as such term is defined in the PJM Operating Agreement, may be an ILR Provider, provided it obtains certification of its load reduction capability as ILR.

2.34 Incremental Auction

"Incremental Auction" shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction), shall be held for the purposes of:

(i) allowing Market Sellers that committed Capacity Resources in the Base Residual Auction for a Delivery Year, which subsequently are determined to be unavailable to deliver the committed Unforced Capacity in such Delivery Year (due to resource retirement, resource cancellation or construction delay, resource derating, EFORD increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences) to submit Buy Bids for replacement Capacity Resources; and

(ii) allowing the Office of the Interconnection to reduce or increase the amount of committed capacity secured in prior auctions for such Delivery Year if, as a result of changed circumstances or expectations since the prior auction(s), there is, respectively, a significant excess or significant deficit of committed capacity for such Delivery Year, for the PJM Region or for an LDA.

2.35 Incremental Capacity Transfer Right

"Incremental Capacity Transfer Right" shall mean a Capacity Transfer Right allocated to a Generation Interconnection Customer or Transmission Interconnection Customer obligated to fund a transmission facility or upgrade, to the extent such upgrade or facility increases the transmission import capability into a Locational Deliverability Area, or a Capacity Transfer Right allocated to a Responsible Customer in accordance with Schedule 12A of the Tariff.

2.36 Interruptible Load for Reliability (ILR)

"Interruptible Load for Reliability" or "ILR" shall have the meaning specified in the Reliability Assurance Agreement.

2.36A Limited Demand Resource

"Limited Demand Resource**"** shall have the meaning specified in the Reliability Assurance Agreement.

2.36B Limited Demand Resource Reliability Target

"Limited Demand Resource Reliability Target**"** for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for the PJM Region or such LDA.

As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) more than ten times over those peak days; and ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result. Second, PJM adopts the lower result from these two tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.37 Load Serving Entity (LSE)

"Load Serving Entity" or "LSE" shall have the meaning specified in the Reliability Assurance Agreement.

2.38 Locational Deliverability Area (LDA)

"Locational Deliverability Area" or "LDA" shall mean a geographic area within the PJM Region that has limited transmission capability to import capacity to satisfy such area's reliability requirement, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, and as specified in Schedule 10.1 of the Reliability Assurance Agreement.

2.39 Locational Deliverability Area Reliability Requirement

"Locational Deliverability Area Reliability Requirement" shall mean the projected internal capacity in the Locational Deliverability Area plus the Capacity Emergency Transfer Objective for the Delivery Year, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, less the minimum internal resources required for all FRR Entities in such Locational Deliverability Area.

2.40 Locational Price Adder

"Locational Price Adder" shall mean an addition to the marginal value of Unforced Capacity within an LDA as necessary to reflect the price of Capacity Resources required to relieve applicable binding locational constraints.

2.41 Locational Reliability Charge

"Locational Reliability Charge" shall have the meaning specified in the Reliability Assurance Agreement.

2.41A Locational UCAP

"Locational UCAP" shall mean unforced capacity that a Member with available uncommitted capacity sells in a bilateral transaction to a Member that previously committed capacity through an RPM Auction but now requires replacement capacity to fulfill its RPM Auction commitment. The Locational UCAP Seller retains responsibility for performance of the resource providing such replacement capacity.

2.41B Locational UCAP Seller

"Locational UCAP Seller" shall mean a Member that sells Locational UCAP.

2.41C Market Seller Offer Cap

"Market Seller Offer Cap" shall mean a maximum offer price applicable to certain Market Sellers under certain conditions, as determined in accordance with section 6 of Attachment DD and section II.E of Attachment M - Appendix.

2.41D Minimum Annual Resource Requirement

"Minimum Annual Resource Requirement" shall mean the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Annual Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Extended Summer Demand Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Extended Summer Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

2.41E Minimum Extended Summer Resource Requirement

"Minimum Extended Summer Resource Requirement" shall mean the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a

separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

2.42 Net Cost of New Entry

"Net Cost of New Entry" shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset, as defined in Section 5.

2.43 Nominated Demand Resource Value

"Nominated Demand Resource Value" shall mean the amount of load reduction that a Demand Resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For existing Demand Resources, the maximum Nominated Demand Resource Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the Base Residual Auction or Incremental Auction is being conducted.

2.43A Nominated Energy Efficiency Value

"Nominated Energy Efficiency Value" shall mean the amount of load reduction that an Energy Efficiency Resource commits to provide through installation of more efficient devices or equipment or implementation of more efficient processes or systems.

2.44 Nominated ILR Value

"Nominated ILR Value" shall mean the amount of load reduction that an ILR resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For ILR, the maximum Nominated ILR Capacity Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the ILR is certified.

2.45 Opportunity Cost

"Opportunity Cost" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.46 Peak-Hour Dispatch

"Peak-Hour Dispatch" shall mean, for purposes of calculating the Energy and Ancillary Services Revenue Offset under section 5 of this Attachment, an assumption, as more fully set forth in the PJM Manuals, that the Reference Resource is *committed in the Day-Ahead Energy Market* in

four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average *day-ahead* LMP for the area for which the Net Cost of New Entry is being determined is greater than, or equal to, the cost to generate (including the cost for a complete start and shutdown cycle) for at least two hours during each four-hour block, where such blocks shall be assumed to be *committed* independently; provided that, if there are not at least two economic hours in any given four-hour block, then the Reference Resource shall be assumed not to be *committed* for such block*; and to the extent not committed in any such block in the Day-Ahead Energy Market under the above conditions based on Day-Ahead LMPs, is dispatched in the Real-Time Energy Market for such block if the Real-Time LMP is greater than or equal to the cost to generate under the same conditions as described above for the Day-Ahead Energy Market.* .

2.47 Peak Season

"Peak Season" shall mean the weeks containing the 24th through 36th Wednesdays of the calendar year. Each such week shall begin on a Monday and end on the following Sunday, except for the week containing the 36th Wednesday, which shall end on the following Friday.

2.48 Percentage Internal Resources Required

"Percentage Internal Resources Required" shall have the meaning specified in the Reliability Assurance Agreement.

2.49 Planned Demand Resource

"Planned Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.50 Planned External Generation Capacity Resource

"Planned External Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.50A Planned Generation Capacity Resource

"Planned Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.51 Planning Period

"Planning Period" shall have the meaning specified in the Reliability Assurance Agreement.

2.52 PJM Region

"PJM Region" shall have the meaning specified in the Reliability Assurance Agreement.

2.53 PJM Region Installed Reserve Margin

"PJM Region Installed Reserve Margin" shall have the meaning specified in the Reliability Assurance Agreement.

2.54 PJM Region Peak Load Forecast

"PJM Region Peak Load Forecast" shall mean the peak load forecast used by the Office of the Interconnection in determining the PJM Region Reliability Requirement, and shall be determined on both a preliminary and final basis as set forth in section 5.

2.55 PJM Region Reliability Requirement

"PJM Region Reliability Requirement" shall mean, for purposes of the Base Residual Auction, the Forecast Pool Requirement multiplied by the Preliminary PJM Region Peak Load Forecast, less the sum of all Preliminary Unforced Capacity Obligations of FRR Entities in the PJM Region; and, for purposes of the Incremental Auctions, the Forecast Pool Requirement multiplied by the updated PJM Region Peak Load Forecast, less the sum of all updated Unforced Capacity Obligations of FRR Entities in the PJM Region.

2.56 Projected PJM Market Revenues

"Projected PJM Market Revenues" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.57 Qualifying Transmission Upgrade

"Qualifying Transmission Upgrade" shall mean a proposed enhancement or addition to the Transmission System that: (a) will increase the Capacity Emergency Transfer Limit into an LDA by a megawatt quantity certified by the Office of the Interconnection; (b) the Office of the Interconnection has determined will be in service on or before the commencement of the first Delivery Year for which such upgrade is the subject of a Sell Offer in the Base Residual Auction; (c) is the subject of a Facilities Study Agreement executed before the conduct of the Base Residual Auction for such Delivery Year and (d) a New Service Customer is obligated to fund through a rate or charge specific to such facility or upgrade.

2.58 Reference Resource

"Reference Resource" shall mean a combustion turbine generating station, configured with two General Electric Frame 7FA turbines with inlet air cooling to 50 degrees, Selective Catalytic Reduction technology *in CONE Areas 1, 2, 3, and 4*, dual fuel capability, and a heat rate of *10.096* Mmbtu/ MWh.

2.59 Reliability Assurance Agreement

"Reliability Assurance Agreement" shall mean that certain "Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region," on file with FERC as PJM Interconnection, L.L.C. Rate Schedule FERC No.44.

2.60 Reliability Pricing Model Auction

"Reliability Pricing Model Auction" or "RPM Auction" shall mean the Base Residual Auction or any Incremental Auction.

2.61 Resource Substitution Charge

"Resource Substitution Charge" shall mean a charge assessed on Capacity Market Buyers in an Incremental Auction to recover the cost of replacement Capacity Resources.

2.61A Scheduled Incremental Auctions

"Scheduled Incremental Auctions" shall refer to the First, Second, or Third Incremental Auction.

2.62 Second Incremental Auction

"Second Incremental Auction" shall mean an Incremental Auction conducted ten months before the Delivery Year to which it relates.

2.63 Sell Offer

"Sell Offer" shall mean an offer to sell Capacity Resources in a Base Residual Auction, Incremental Auction, or Reliability Backstop Auction.

2.64 [Reserved for Future Use]

2.65 Self-Supply

"Self-Supply" shall mean Capacity Resources secured by a Load-Serving Entity, by ownership or contract, outside a Reliability Pricing Model Auction, and used to meet obligations under this Attachment or the Reliability Assurance Agreement through submission in a Base Residual Auction or an Incremental Auction of a Sell Offer indicating such Market Seller's intent that such Capacity Resource be Self-Supply. Self-Supply may be either committed regardless of clearing price or submitted as a Sell Offer with a price bid. A Load Serving Entity's Sell Offer with a price bid for an owned or contracted Capacity Resource shall not be deemed "Self-Supply," unless it is designated as Self-Supply and used by the LSE to meet obligations under this Attachment or the Reliability Assurance Agreement.

2.65A Short-Term Resource Procurement Target

"Short-Term Resource Procurement Target" shall mean, as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the

PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA.

2.65B Short-Term Resource Procurement Target Applicable Share

"Short-Term Resource Procurement Target Applicable Share" shall mean: (i) for the PJM Region, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction and, as to the Third Incremental Auction for the PJM Region, 0.6 times such target; and (ii) for an LDA, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction for such LDA and, as to the Third Incremental Auction, 0.6 times such target.

2.66 Third Incremental Auction

"Third Incremental Auction" shall mean an Incremental Auction conducted three months before the Delivery Year to which it relates.

2.67 Transition Adder

"Transition Adder" shall mean a component of a Sell Offer permitted for certain Capacity Market Sellers for the Transition Period, as set forth in section 17.

2.68 Transition Period

"Transition Period" shall mean the four-year period consisting of the Delivery Years commencing June 1, 2007, June 1, 2008, June 1, 2009, and June 1, 2010.

2.69 Unforced Capacity

"Unforced Capacity" shall have the meaning specified in the Reliability Assurance Agreement.

2.69A Updated VRR Curve

"Updated VRR Curve" shall mean the Variable Resource Requirement Curve as defined in section 5.10(a) of this Attachment for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect the Short-term Resource Procurement Target applicable to the relevant Incremental Auction and any change in the Reliability Requirement from the Base Residual Auction to such Incremental Auction.

2.69B 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.

2.69C 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.

2.70 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 Section 5.

2.71 Zonal Capacity Price

"Zonal Capacity Price" shall mean the clearing price required in each Zone to meet the demand for Unforced Capacity and satisfy Locational Deliverability Requirements for the LDA or LDAs associated with such Zone. If the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA.

5.8 Submission of Sell Offers and Buy Bids

Submission of Sell Offers and Buy Bids shall be subject to the following requirements:

a) A Sell Offer or Buy Bid that fails to specify a positive megawatt quantity shall be rejected by the Office of the Interconnection.

b) A Buy Bid that fails to specify price shall be rejected by the Office of the Interconnection. A Sell Offer that fails to either designate such offer as self-scheduled or to specify an offer price shall be rejected by the Office of the Interconnection.

c) A Buy Bid that fails to designate the type of Unforced Capacity desired, i.e., an Annual Resource, Extended Summer Demand Resource, or Limited Demand Resource, shall be rejected by the Office of the Interconnection.

d) All Sell Offers and Buy Bids must be received by the Office of the Interconnection during a specified period, as determined by the Office of the Interconnection, in accordance with the PJM Manuals. A Sell Offer or Buy Bid may be withdrawn by a notification of withdrawal received by the Office of the Interconnection at any time during the foregoing period, but may not be withdrawn after such period.

e) Sell Offers or Buy Bids shall be submitted or withdrawn via the Internet site designated by the Office of the Interconnection; provided, however, that if the Internet site cannot be accessed at any time during the period specified for the applicable auction, a Sell Offer or Buy Bid may be submitted or withdrawn by electronic mail transmitted to the e-mail address, or faxed to the fax number specified by the Office of the Interconnection.

f) Sell Offers must be based on the Capacity Market Seller's Capacity Resource position at the opening of the auction's bidding window.

g) The Office of the Interconnection shall accept a Sell Offer only up to the megawatt amount of installed capacity of Capacity Resources owned or controlled by such Capacity Market Seller that has not previously been committed for the applicable Delivery Year.

h) No Sell Offer shall be accepted from an FRR Entity unless it meets the requirements applicable to such offers under Schedule 8.1 of the Reliability Assurance Agreement.

i) The Office of the Interconnection shall have final authority to determine whether to accept a Sell Offer in accordance with the terms of the Tariff and the PJM Manuals.

5.15 Capacity Transfer Rights

(a) To recognize the value of Import Capability and provide a partial offset to potential Locational Price Adders that may be determined for an LDA (as to any Zone that encompasses two or more LDAs, the term "LDA" as used herein shall refer to such Zone, rather than to the LDAs it encompasses), the Office of the Interconnection shall allocate Capacity Transfer Rights to each LSE serving load in such LDA pro rata based on such LSE's Daily Unforced Capacity Obligation in such LDA. The total megawatts of Capacity Transfer Rights available for allocation shall equal the megawatts of Unforced Capacity imported into such LDA determined based on the results of the Base Residual Auction and Incremental Auctions ("Capacity Imported"), less any megawatts of CETL increase into such LDA attributable to Qualifying Transmission Upgrades cleared in an RPM Auction and any Incremental Capacity Transfer Rights into such LDA allocated pursuant to section 5.16 (but not less than zero), and shall be subject to change in subsequent Delivery Years as a result of changes in the quantity of such Capacity Imported into such LDA. Each change in an LSE's Daily Unforced Capacity Obligation during a Delivery Year shall result in a corresponding change in the Capacity Transfer Rights allocated to such LSE.

(b) For LDAs in which the RPM Auctions for the Delivery Year resulted in a positive average weighted Locational Price Adder with respect to the immediate higher level LDA, the holder of the Capacity Transfer Rights in such LDA shall receive a payment during the Delivery Year equal to (i) the average weighted Locational Price Adder for such LDA determined with respect to the immediate higher level LDA as a result of all RPM Auctions for such Delivery Year, multiplied by (ii) the megawatt quantity of the Capacity Transfer Right allocated to such LSE in such LDA.

(c) Capacity Transfer Rights shall be transferable. A purchaser of Capacity Transfer Rights from the original party allocated such rights shall receive any payments due under this section or section 5.16, provided the seller and purchaser of such rights timely notify the Office of the Interconnection of such purchase, in accordance with procedures specified in the PJM manuals.

5.16 Incremental Capacity Transfer Rights

(a) The Office of the Interconnection shall allocate Incremental Capacity Transfer Rights to a New Service Customer (or, for facilities or upgrades in a PJM queue prior to March 1, 2007, to an Interconnection Customer) obligated to fund a transmission facility or upgrade through a rate or charge specific to such facility or upgrade, to the extent such upgrade or facility increases the Import Capability into a Locational Deliverability Area, with respect to any such transmission facility or upgrade interconnected to the Transmission System pursuant to Part IV of this Tariff, including transmission facilities or upgrades interconnected to the Transmission System pursuant to Part IV prior to the effective date of this Attachment. Incremental Capacity Transfer Rights shall be available for a facility or upgrade for a Delivery Year only if the Office of the Interconnection certifies the quantity of Import Capability provided by such facility or upgrade at least 45 days prior to the Base Residual Auction for such Delivery Year. The megawatt quantity of Incremental Capacity Transfer Rights allocated to such a New Service Customer (or Interconnection Customer) shall equal the megawatt quantity of the increase in Import Capability across a locational constraint resulting from such upgrade or facility, provided that the total Incremental Capacity Transfer Rights awarded as to an LDA (including those allocated pursuant to Schedule 12A of the Tariff) may not exceed the total Capacity Transfer Rights determined as to such LDA. A Capacity Market Seller that offers and clears a Qualifying Transmission Upgrade in the Base Residual Auction for a Delivery Year shall not receive Incremental Capacity Transfer Rights with respect to such upgrade for such Delivery Year. Terms and conditions for the allocation of Incremental Capacity Transfer Rights to New Service Customers shall be as further set forth in Part VI of this Tariff, and those for the allocation of Incremental Capacity Transfer Rights to Responsible Customers shall be as further set forth in Schedule 12A of this Tariff.

(b) For LDAs in which the RPM Auctions for such Delivery Year result in a positive average weighted Locational Price Adder with respect to the immediate higher level LDA, the holder of an Incremental Capacity Transfer Right into such LDA shall receive a payment equal to the average weighted Locational Price Adder for the LDA into which the associated facility or upgrade increased Import Capability, multiplied by the megawatt quantity of the Incremental Capacity Transfer Right allocated to such Interconnection Customer.

6. MARKET POWER MITIGATION

6.1 Applicability

The provisions of the Market Monitoring Plan (in Attachment M and Attachment - M Appendix to this Tariff and this section 6) shall apply to the Reliability Pricing Model Auctions.

6.2 Process

(a) By no later than 90 days (or such other time period as established for purposes of the Transition Period) prior to the conduct of the Base Residual Auction and each Incremental Auction for such Delivery Year, the Office of the Interconnection shall post or continue to post the results of the Market Monitoring Unit's application of the Preliminary Market Structure Screen determined pursuant to section II.D of Attachment M - Appendix.

(b) In accordance with the schedule specified in the PJM Manuals, following PJM's conduct of a Base Residual Auction or Incremental Auction pursuant to section 5.12, but prior to the Office of the Interconnection's final determination of clearing prices and charges pursuant to section 5.14, the Office of the Interconnection shall: (i) apply the Market Structure Test to any LDA having a Locational Price Adder greater than zero and to the entire PJM region; (ii) apply Market Seller Offer Caps, if required under this section 6; and (iii) recompute the optimization algorithm to clear the auction with the Market Seller Offer Caps in place.

(c) Within seven days after the deadline for submission of Sell Offers in a Base Residual Auction or Incremental Auction, the Office of the Interconnection shall file with FERC a report of any determination made pursuant to sections 5.14(h), 6.5(a)(ii), or 6.7(c) identified in such sections as subject to the procedures of this section. Such report shall list each such determination, the information considered in making each such determination, and an explanation of each such determination. Any entity that objects to any such determination may file a written objection with FERC no later than seven days after the filing of the report. Any such objection must not merely allege that the determination was in error, and must provide support for the objection, demonstrating that the determination overlooked or failed to consider relevant evidence. In the event that no objection is filed, the determination shall be final. In the event that an objection is filed, FERC shall issue any decision modifying the determination no later than 60 days after the filing of such report; otherwise, the determination shall be final. Final auction results shall reflect any decision made by FERC regarding the report.

6.3 Market Structure Tests

(a) Preliminary Market Structure Screen.

The Market Monitoring Unit shall apply the Preliminary Market Structure Screen pursuant to section II.D of Attachment M - Appendix. Potential Capacity Market Sellers owning or controlling any Existing Generation Capacity Resources in the PJM Region shall be required to provide to the Market Monitoring Unit the additional information specified in section II.D of Attachment M - Appendix if such Generation Capacity is located in an LDA, "Unconstrained

LDA Group" (as defined in Attachment M - Appendix), or the entire PJM Region that fails the Preliminary Market Structure Screen, as applied pursuant to section II.D below.

(b) Market Structure Test.

A constrained LDA or the PJM Region shall fail the Market Structure Test, and mitigation shall be applied to all jointly pivotal suppliers (including all Affiliates of such suppliers, and all third-party supply in the relevant LDA controlled by such suppliers by contract), if, as to the Sell Offers that comprise the incremental supply determined pursuant to section 6.3(c) that are based on Generation Capacity Resources, there are not more than three jointly pivotal suppliers. The Office of the Interconnection shall apply the Market Structure Test. The Office of the Interconnection shall confirm the results of the Market Structure Test with the Market Monitoring Unit.

(c) Determination of Incremental Supply

In applying the Market Structure Test, the Office of the Interconnection shall consider all (i) incremental supply (provided, however, that the Office of the Interconnection shall consider only such supply available from Generation Capacity Resources) available to solve the constraint applicable to a constrained LDA offered at less than or equal to 150% of the cost-based clearing price; or (ii) supply for the PJM Region, offered at less than or equal to 150% of the cost-based clearing price, provided that supply in this section includes only the lower of cost-based or priced based offers from Generation Capacity Resources. Cost-based clearing prices are the prices resulting from the RPM auction algorithm using the lower of cost-based or price-based offers for all Capacity Resources.

6.4 Market Seller Offer Caps

(a) The Market Seller Offer Cap, stated in dollars per MW-day of unforced capacity, applicable to price-quantity offers within the Base Offer Segment for an Existing Generation Capacity Resource shall be the Avoidable Cost Rate for such resource, less the Projected PJM Market Revenues for such resource, stated in dollars per MW of unforced capacity. During the first three Delivery Years of the Transition Period, the Market Seller Offer Cap shall be increased for Sell Offers submitted by eligible Capacity Market Sellers in any Unconstrained LDA Group by the Transition Adder set forth in section 17.5 of this Attachment. The Market Seller Offer Cap for an Existing Generation Capacity Resource shall be the Opportunity Cost for such resource, if applicable, as determined in accordance with section 6.7. Nothing herein shall preclude any Capacity Market Seller and the Market Monitoring Unit from agreeing to, nor require either such entity to agree to, an alternative market seller offer cap determined on a mutually agreeable basis. Any such alternative offer cap shall be filed with the Commission for its approval. This provision is duplicated in section II.E.3 of Attachment M- Appendix.

(b) For each Existing Generation Capacity Resource, a potential Capacity Market Seller must timely provide to the Market Monitoring Unit data and documentation required under section 6.6 to establish the level of the Market Seller Offer Cap applicable to each resource. The Capacity Market Seller must promptly address any concerns identified by the Market Monitoring Unit regarding the data and documentation provided, review the proposed

Market Seller Offer Cap, and attempt to reach agreement with the Market Monitoring Unit on the level of the Market Seller Offer Cap.

(c) If the Market Monitoring Unit informs the Office of the Interconnection that a Capacity Market Seller has failed to submit costs consistent with section 6.7, it shall be required to submit any Sell Offer in the applicable auction as Self-Supply committed regardless of clearing price. If such Capacity Market Seller submits a Sell Offer that is not Self-Supply committed regardless of clearing price, the Market Monitoring Unit may seek relief from the Commission pursuant to section II.E of Attachment M - Appendix.

(d) In the event that a Capacity Market Seller and the Market Monitoring Unit cannot agree on the level of a Market Seller Offer Cap, the Office of the Interconnection shall make its own determination of the level of the Market Seller Offer Cap based on the requirements of the Tariff and the PJM Manuals. If the Capacity Market Seller submits a Sell Offer that the Office of the Interconnection determines would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction compared to the Office of the Interconnection's determination of the level of the Market Seller Offer Cap, the Office of the Interconnection shall apply to FERC for an order, on an expedited basis, directing such Capacity Market Seller to submit a Sell Offer consistent with the Office of the Interconnection's determination, or for other appropriate relief, and PJM shall postpone clearing the auction pending FERC's decision on the matter. Should the Market Monitoring Unit exercise its powers to inform Commission staff of its concerns and request a determination, on an expedited basis, directing a Capacity Market Seller to submit a Sell Offer consistent with the Market Monitoring Unit's determination, or for other appropriate relief, pursuant to section II.E of Attachment M - Appendix, PJM may postpone clearing the auction pending FERC's decision on the matter.

(e) Nothing in this section precludes the Capacity Market Seller from filing a petition with FERC seeking a determination of whether the Sell Offer complies with the requirements of the Tariff.

(f) Notwithstanding the foregoing, a Capacity Market Seller may submit a Sell Offer that it chooses, provided that (i) it has participated in good faith with the process described in this section 6.4 and in section II.E of Attachment M - Appendix, (ii) the offer is no higher than the level defined in any agreement reached by the Capacity Market Seller and the Market Monitoring Unit that resulted from the foregoing process, and (iii) the offer is accepted by the Office of the Interconnection subject to the criteria set forth in the Tariff and the PJM Manuals.

(g) For any Third Incremental Auction, the Market Seller Offer Cap for an Existing Generation Capacity Resource shall be determined pursuant to paragraph (a) of this Section 6.4, or if elected by the Capacity Market Seller, shall be equal to 1.1 times the Capacity Resource Clearing Price in the Base Residual Auction for the relevant LDA and Delivery Year.

6.5 Mitigation

The Office of the Interconnection shall apply market power mitigation measures in any Base Residual Auction or Incremental Auction for any LDA, Unconstrained LDA Group, or the PJM Region that fails the Market Structure Test.

(a) Mitigation for Generation Capacity Resources.

i) Existing Generation Capacity Resource

Mitigation will be applied on a unit-specific basis and only if the Sell Offer of Unforced Capacity from an Existing Generation Capacity Resource: (1) is greater than the Market Seller Offer Cap applicable to such resource; and (2) would, absent mitigation, increase the Capacity Resource Clearing Price in the relevant auction. If such conditions are met, such Sell Offer shall be set equal to the Market Seller Offer Cap.

ii) Planned Generation Capacity Resources

(A) Sell Offers based on Planned Generation Capacity Resources (including External Planned Generation Capacity Resources) shall be presumed to be competitive and shall not be subject to market power mitigation in any Base Residual Auction or Incremental Auction for which such resource qualifies as a Planned Generation Capacity Resource, but any such Sell Offer shall be rejected if it meets the criteria set forth in subsection (C) below, unless the Capacity Market Seller obtains approval from FERC for use of such offer prior to the deadline for submission of such offers in the applicable auction. Such resources are Existing Generation Capacity Resources in the auctions for any Delivery Year following the Delivery Year for which such resource cleared an RPM Auction. Such resources may receive certain price assurances for the two Delivery Years immediately following the first Delivery Year of service under certain conditions as set forth in section 5.14 of this Attachment. Notwithstanding the foregoing, a Generation Capacity Resource for which construction has not commenced and which would otherwise have been treated as a Planned Generation Capacity Resource but for the fact that it was bid into RPM Auctions for at least two consecutive Delivery Years, and cleared the last such auction only because it was considered existing and its mitigated offer cap was accepted when its price offer would not have otherwise been accepted, shall be deemed to be a Planned Generation Capacity Resource.

(B) Sell Offers based on Planned Generation Capacity Resources (including External Planned Generation Capacity Resources) submitted for the first year in which such resources qualify as Planned Generation Capacity Resources shall be deemed competitive and not be subject to mitigation if: (1) collectively all such Sell Offers provide Unforced Capacity in an amount equal to or greater than two times the incremental quantity of new entry required to meet the LDA Reliability Requirement; and (2) at least two unaffiliated suppliers have submitted Sell Offers for Planned Generation Capacity Resources in such LDA. Notwithstanding the foregoing, any Capacity Market Seller, together with Affiliates, whose Sell Offers based on Planned Generation Capacity Resources in that LDA are pivotal, shall be subject to mitigation.

(C) Where the two conditions stated in subsection (B) are not met, or the Sell Offer is pivotal, the Sell Offer shall be rejected if it exceeds 140 percent of: 1) the average of location-adjusted Sell Offers for Planned Generation Capacity Resources from the same asset class as such Sell Offer, submitted (and not rejected) (Asset-Class New Plant Offers) for such Delivery Year; or 2) if there are no Asset-Class New Plant Offers for such Delivery Year, the average of Asset-Class New Plant Offers for all prior Delivery Years; or 3) if there are no Asset-Class New Plant Offers for any prior Delivery Year, the Net CONE applicable for such Delivery Year in the LDA for which such offer was submitted. For purposes of this section, asset classes shall be as stated in section 6.7(c) as effective for such Delivery Year, and Asset-Class New Plant Offers shall be location-adjusted by the ratio between the Net CONE effective for such Delivery Year for the LDA in which the Sell Offer subject to this section was submitted and the average, weighted by installed capacity, of the Net CONEs for all LDAs in which the units underlying such Asset Class New Plant Offers are located. Following the conduct of the applicable auction and before the final determination of clearing prices, in accordance with Section 6.2(b) above, each Capacity Market Seller whose Sell Offer is so rejected shall be notified and allowed an opportunity to submit a revised Sell Offer that does not exceed such threshold. The Office of the Interconnection then shall clear the auction with such revised Sell Offer in place.

(b) Mitigation for Demand Resources

The Market Seller Offer Cap shall not be applied to Sell Offers of Demand Resources or Energy Efficiency Resources.

6.6 Offer Requirement for Capacity Resources

(a) To avoid application of subsection (h), all of the installed capacity of all Existing Generation Capacity Resources located in the PJM Region shall be offered by the Capacity Market Seller that owns or controls all or part of such resource (which may include submission as Self-Supply) in all RPM Auctions for each Delivery Year, less any amount determined by the Office of the Interconnection to be eligible for an exception to the must-offer requirement, where installed capacity is determined as of the date on which bidding commences for each RPM Auction pursuant to Section 5.6.6 of Attachment DD of the Tariff. The Unforced Capacity of such resources is determined using the EFORd value that is submitted by the Capacity Market Seller in its Sell Offer, which shall not exceed the maximum EFORd for that resource as defined in Section 6.6(b). If a resource should be included on the list of Existing Generation Capacity Resources subject to the must-offer requirement that is maintained by the Market Monitoring Unit pursuant to Section II.C.1 of Attachment M – Appendix of the Tariff, but is omitted therefrom whether by mistake of the Market Monitoring Unit or failure of the Capacity Market Seller that owns or controls all or part of such resource to provide information about the resource

to the Market Monitoring Unit, this shall not excuse such resource from the must-offer requirement.

(b) For each Existing Generation Capacity Resource, a potential Capacity Market Seller must timely provide to the Market Monitoring Unit data and documentation required under section 6.6 to establish the maximum EFORd applicable to each resource. The maximum EFORd that may be used in a Sell Offer for Base Residual Auctions, First Incremental Auctions and Second Incremental Auctions, and for Conditional Incremental Auctions held prior to the date on which the final EFORds used for a Delivery Year are posted, is the greater of (i) the average EFORd for the five consecutive years ending on the September 30 that last precedes the Base Residual Auction, or (ii) the EFORd for the 12 months ending on the September 30 that last precedes the Base Residual Auction. The maximum EFORd that may be used in a Sell Offer for Third Incremental Auctions, and for Conditional Incremental Auctions held after the date on which the final EFORd used for a Delivery Year is posted, is the EFORd for the 12 months ending on the September 30 that last precedes the submission of such offers. The Capacity Market Seller must promptly address any concerns identified by the Market Monitoring Unit regarding the data and documentation provided, review the proposed maximum EFORd, and attempt to reach agreement with the Market Monitoring Unit on the maximum level of the EFORd

(c) If the Market Monitoring Unit informs the Office of the Interconnection that a Capacity Market Seller has failed to submit costs consistent with section 6.7, it shall be required to submit any Sell Offer in the applicable auction as Self-Supply committed regardless of clearing price. If such Capacity Market Seller submits a Sell Offer that is not Self-Supply committed regardless of clearing price, the Market Monitoring Unit may seek relief from the Commission pursuant to section 6.4(d) below and section II.E of Attachment M - Appendix.

(d) In the event that a Capacity Market Seller and the Market Monitoring Unit cannot agree on the maximum level of the EFORd, the Office of the Interconnection shall make its own determination of the maximum level of the EFORd based on the requirements of the Tariff and the PJM Manuals. If the Capacity Market Seller submits an EFORd that the Office of the Interconnection determines would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction compared to the Office of the Interconnection's determination of the maximum level of the EFORd, the Office of the Interconnection shall apply to FERC for an order, on an expedited basis, directing such Capacity Market Seller to submit an EFORd consistent with the Market Monitoring Unit's determination, or for other appropriate relief, and PJM shall postpone clearing the auction pending FERC's decision on the matter. Should the Market Monitoring Unit exercise its powers to inform Commission staff of its concerns and request a determination, on an expedited basis, directing a Capacity Market Seller to submit an EFORd consistent with the Market Monitoring Unit's determination, or for other appropriate relief, pursuant to section II.C of Attachment M - Appendix, PJM may postpone clearing the auction pending FERC's decision on the matter.

(e) Nothing in this section precludes the Capacity Market Seller from filing a petition with FERC seeking a determination of whether the EFORd complies with the requirements of the Tariff.

(f) Notwithstanding the foregoing, a Capacity Market Seller may submit an EFORd that it chooses, provided that (i) it has participated in good faith with the process described in this section 6.6 and in section II.C of Attachment M - Appendix, (ii) the offer is no higher than the level defined in any agreement reached by the Capacity Market Seller and the Market Monitoring Unit that resulted from the foregoing process, and (iii) the offer is accepted by the Office of the Interconnection subject to the criteria set forth in the Tariff and the PJM Manuals.

(g) A Capacity Market Seller that owns or controls an existing generation resource in the PJM Region that is capable of qualifying as an Existing Generation Capacity Resource as of the date on which bidding commences for an RPM Auction may not avoid the rule in subsection (a) or be removed from Capacity Resource status by failing to qualify as a Generation Capacity Resource, or by attempting to remove a unit previously qualified as a Generation Capacity Resource from classification as a Capacity Resource for that RPM Auction.However, generation resource may qualify for an exception to the must-offer requirement, as shown by appropriate documentation, if the Capacity Market Seller that owns or controls such resource demonstrates that it: (i) is reasonably expected to be physically unable to participate in the relevant Delivery Year; (ii) has a financially and physically firm commitment to an external sale of its capacity, or (iii) was interconnected to the Transmission System as an Energy Resource and not subsequently converted to a Capacity Resource.

In order to establish that a resource is reasonably expected to be physically unable to participate in the relevant auction as set forth in (i) above, the Capacity Market Seller must demonstrate that:

A. It has a documented plan in place to retire the resource prior to or during the Delivery Year, and has submitted a notice of Deactivation to the Office of the Interconnection consistent with Section 113.1 of the PJM Tariff, without regard to whether the Office of the Interconnection has requested the Capacity Market Seller to continue to operate the resource beyond its desired deactivation date in accordance with Section 113.2 of the PJM Tariff for the purpose of maintaining the reliability of the PJM Transmission System and the Capacity Market Seller has agreed to do so;

B. Significant physical operational restrictions cause long term or permanent changes to the installed capacity value of the resource, or the resource is under major repair that will extend into the applicable Delivery Year, that will result in the imposition of RPM performance penalties pursuant to Attachment DD of the PJM Tariff;

C. The Capacity Market Seller is involved in an ongoing regulatory proceeding (e.g. – regarding potential environmental restrictions) specific to the resource and has received an order, decision, final rule, opinion or other final directive from the regulatory authority that will result in the retirement of the resource; or

D. A resource considered an Existing Generating Capacity Resource because it cleared an RPM Auction for a Delivery Year prior to the Delivery Year of the relevant auction, but which is not yet in service, is unable to achieve full commercial operation prior to the Delivery Year of the relevant auction. The Capacity Market Seller must submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized

statement of a corporate officer certifying that the resource will not be in full commercial operation prior to the referenced Delivery Year.

In order to establish that a resource has a financially and physically firm commitment to an external sale of its capacity as set forth in (ii) above, the Capacity Market Seller must demonstrate that it has entered into a unit-specific bilateral transaction for service to load located outside the PJM Region, by a demonstration that such resource is identified on a unit-specific basis as a network resource under the transmission tariff for the control area applicable to such external load, or by an equivalent demonstration of a financially and physically firm commitment to an external sale. The Capacity Market Seller additionally shall identify the megawatt amount, export zone, and time period (in days) of the export.

A Capacity Market Seller that seeks to remove a Generation Capacity Resource from PJM Capacity Resource status and/or seeks approval for an exception to the must-offer requirement shall first submit such request to the Market Monitoring Unit for evaluation. A Capacity Market Seller may only remove the Generation Capacity Resource from PJM Capacity Resource status if (i) the Market Monitoring Unit has determined that the Generation Capacity Resource meets the applicable criteria set forth in Sections 5.6.6 and 6.6 of Attachment DD and the Office of the Interconnection agrees with this determination, or, (ii) the potential Capacity Market Seller and the Market Monitoring Unit cannot come to agreement on whether a Generation Capacity Resource should be removed from PJM Capacity Resource status or satisfied the criteria for an exception to the must-offer requirement, the potential Capacity Market Seller has submitted its request to remove the resource from PJM Capacity Resource status to the Office of the Interconnection, and the Office of the Interconnection has determined that the Generation Capacity Resource meets the applicable criteria set forth in Sections 5.6.6 and 6.6 of Attachment DD. Nothing herein shall require a Market Seller to offer its resource into an RPM Auction prior to seeking to remove a resource from Capacity Resource status, subject to satisfaction of Section 6.6.

After the Market Monitoring Unit has made its determination of whether a resource has satisfied the must-offer requirement or meets one of the exceptions thereto and has notified the Capacity Market Seller and the Office of the Interconnection of the same pursuant to Section II.C.4 of Attachment M – Appendix, the Office of the Interconnection shall approve or deny the exception request. The exception request shall be deemed to be approved or denied by the Office of the Interconnection, consistent with the determination of the Market Monitoring Unit, unless the Office of the Interconnection notifies the Capacity Market Seller and Market Monitoring Unit that it disagrees with the Market Monitoring Unit's determination. After the Market Monitoring Unit and the Office of the Interconnection have made their determinations of whether a resource meets the criteria to qualify for an exception to the must-offer requirement and prior to the date on which bidding commences for the applicable RPM Auction, the Capacity Market Seller must notify the Market Monitoring Unit and the Office of the Interconnection whether it intends to exclude from its Sell Offer some or all of the subject capacity on the basis of an identified exception. PJM does not make determinations of whether withholding of capacity constitutes market power. A Generation Capacity Resource that does not qualify for submission into an RPM Auction because it is not owned or controlled by the Capacity Market Seller for a full Delivery Year is not subject to the offer requirement hereunder; provided, however, that a Capacity Market Seller planning to transfer ownership or control of a Generation

Capacity Resource during a Delivery Year pursuant to a sale or transfer agreement shall be required to satisfy the offer requirement hereunder for the entirety of such Delivery Year and may satisfy such requirement by providing for the assumption of this requirement by the transferee of ownership or control under such agreement.

(h) Any existing generation resource located in the PJM Region that satisfies the criteria in the definition of Existing Generation Capacity Resource as of the date on which bidding commences for the Base Residual Auction for a Delivery Year, that is not offered into such Base Residual Auction, and that does not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any subsequent Incremental Auctions conducted for such Delivery Year; (ii) shall not receive any payments under section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

All generation resources located in the PJM Region that satisfy the criteria in the definition of Existing Generation Capacity Resource as of the date on which bidding commences for an Incremental Auction for a particular Delivery Year, but that did not satisfy such criteria as of the date that on which bidding commenced in the Base Residual Auction for that Delivery Year, that is not offered into that Incremental Auction, and that does not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any subsequent Incremental Auctions conducted for such Delivery Year; (ii) shall not receive any payments under section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

All Existing Generation Capacity Resources that are offered into a Base Residual Auction or Incremental Auction for a particular Delivery Year but do not clear in such auction, that are not offered into each subsequent Incremental Auction, and that do not meet any of the exceptions stated in the prior subsection (g): (i) may not participate in any Incremental Auctions conducted for such Delivery Year subsequent to such failure to offer; (ii) shall not receive any payments under section 5.14 for such Delivery Year for the capacity of such Generation Capacity Resources; and (iii) shall not be permitted to satisfy any LSE's Unforced Capacity Obligation, or any entity's obligation to obtain the commitment of Capacity Resources, for such Delivery Year.

Any such Existing Generation Capacity Resources may also be subject to further action by the Market Monitoring Unit under the terms of Attachment M and Attachment M – Appendix.

(i) In addition to the remedies set forth in subsections (g) and (h) above, if the Market Monitoring Unit determines that one or more Capacity Market Sellers' failure to offer part or all of one or more existing generation resources, for which the Office of the Interconnection has not approved an exception to the must-offer requirement, into an RPM Auction as required by this Section 6.6 would result in an increase of greater than five percent in any Zonal Capacity Price determined through such auction, and the Office of the Interconnection agrees with that determination, the Office of the Interconnection shall apply to FERC for an order, on an expedited basis, directing such Capacity Market Seller to participate in the relevant RPM Auction, or for other appropriate relief, and PJM will postpone clearing the auction

pending FERC's decision on the matter. If the Office of the Interconnection disagrees with the Market Monitoring Unit's determination and does not apply to FERC for an order directing the Capacity Market Seller to participate in the auction or for other appropriate relief, the Market Monitoring Unit may exercise its powers to inform Commission staff of its concerns and to seek appropriate relief.

6.7 Data Submission

(a) Potential participants in any PJM Reliability Pricing Model Auction shall submit, together with supporting documentation for each item, to the Market Monitoring Unit no later than four months prior to the posted date for the conduct of such auction, a list of owned or controlled generation resources by PJM transmission zone for the specified Delivery Year, including the amount of gross capacity, the EFORd and the net (unforced) capacity.

(b) Except as provided in subsection (c) below, potential participants in any PJM Reliability Pricing Model Auction in any LDA or Unconstrained LDA Group that fails the Preliminary Market Structure Screen (or, if such region fails the screen, potential auction participants in the entire PJM Region) shall, in addition, submit the following data, together with supporting documentation for each item, to the Market Monitoring Unit no later than two months prior to the conduct of such auction:

i. If the Capacity Market Seller intends to submit a non-zero price in its Sell Offer in any such auction, the Capacity Market Seller shall submit a calculation of the Avoidable Cost Rate and Projected PJM Market Revenues, as defined in subsection (d) below, together with detailed supporting documentation.

ii. If the Capacity Market Seller intends to submit a Sell Offer based on opportunity cost, the Capacity Market Seller shall also submit a calculation of Opportunity Cost, as defined in subsection (d), with detailed supporting documentation.

(c) Potential auction participants identified in subsection (b) above need not submit the data specified in that subsection for any Generation Capacity Resource:

i. that is in an Unconstrained LDA Group or, if this is the relevant market, the entire PJM Region, and is in a resource class identified in the table below as not likely to include the marginal price-setting resources in such auction; or

ii. for which the potential participant commits that any Sell Offer it submits as to such resource shall not include any price above: (1) the level identified below for the relevant resource class, less (2) the Projected PJM Market Revenues for such resource, as determined in accordance with this Tariff.

Nothing herein precludes the Market Monitoring Unit from requesting additional information from any potential auction participant as deemed necessary by the Market Monitoring Unit, including, without limitation, additional cost data on resources in a class that is not otherwise expected to include the marginal price setting resource; and compliance with such request shall be a condition of participation in any auction. Any Sell Offer submitted in any auction that is

inconsistent with any commitment made pursuant to this subsection shall be rejected, and the Capacity Market Seller shall be required promptly to resubmit a Sell Offer that complies with such commitments. If the Capacity Market Seller does not timely resubmit its Sell Offer, it shall be deemed to have submitted a Sell Offer that complies with the commitments made under this subsection, with a default price equal to the maximum price for the class of resource determined under section (c)(ii) above. The obligation imposed under section 6.6(a) shall not be satisfied unless and until the Capacity Market Seller submits (or is deemed to have submitted) a Sell Offer that conforms to its commitments made pursuant to this subsection or subject to the procedures set forth in section 6.4 and section II.H of Attachment M - Appendix. The default Avoidable Cost Rates referenced in section (c)(ii) above are as set forth in the tables below for any auction conducted after September 1, 2009 for any Delivery Year through the 2012-2013 Delivery Year. To determine the default ACR values for the 2013-2014 and subsequent Delivery Years, the Office of the Interconnection shall multiply the ACR values for the immediately preceding Delivery Year by a factor equal to the most recent ten-calendar-year annual average rate of change in the applicable Handy-Whitman Index of Public Utility Construction Costs or a comparable index approved by the Commission, as calculated by the Office of the Interconnection and posted to its Web site; provided, however, that after the Handy-Whitman indexing methodology has been employed to determine the default ACR values for the RPM Auctions for three consecutive Delivery Years, the Office of the Interconnection shall: i) review the default ACR values to determine whether any changes other than those produced by such methodology are warranted for subsequent Delivery Years (including seeking the analysis and advice of the Market Monitoring Unit on such matter) and report its conclusions to the Members in writing no later than four months after the Base Residual Auction for the third such Delivery Year; and ii) file with FERC resulting changes, if any, to this section no later than seven months after such Base Residual Auction, to be effective for the Base Residual Auction for the following Delivery Year; provided further, that nothing herein precludes the Office of the Interconnection from filing with FERC changes to the default ACR values or any other provision of this section prior to the deadline stated in the previous clause, or at any other time. Capacity Market Sellers shall use the one-year mothball Avoidable Cost Rate shown below, unless such Capacity Market Seller satisfies the criteria set forth in section 6.7(e), in which case the Capacity Market Seller may use the retirement Avoidable Cost Rate. PJM shall also publish on its Web site the number of Generation Capacity Resources and megawatts per LDA that use the retirement Avoidable Cost Rates.

Technology Classes Not Likely to be the Marginal Price Setting Resource						
Technology	**2010-2011 Mothball Avoidable Cost Rate ($/MW-Day)**	**2010-2011 Retirement Avoidable Cost Rate ($/MW-Day)**	**2011-2012 Mothball Avoidable Cost Rate ($/MW-Day)**	**2011-2012 Retirement Avoidable Cost Rate ($/MW-Day)**	**2012-2013 Mothball Avoidable Cost Rate ($/MW-Day)**	**2012 -2013 Retirement Avoidable Cost Rate ($/MW-Day)**
Nuclear	N/a	N/a	N/a	N/a	N/a	N/a
Pumped Storage	$20.77	$29.17	$21.72	$30.50	$22.71	$31.89
Hydro	$71.01	$92.87	$74.24	$97.10	$77.62	$101.52
Sub-Critical Coal	$170.48	$188.98	$178.24	$197.58	$186.35	$206.57
Super Critical Coal	$176.13	$192.65	$184.15	$201.42	$192.53	$210.59
Waste Coal - Small	$224.83	$272.31	$235.06	$284.70	$245.75	$297.65
Waste Coal – Large	$83.15	$100.45	$86.94	$105.02	$90.89	$109.80
Wind	N/a	N/a	N/a	N/a	N/a	N/a

Maximum Avoidable Cost Rates by Technology Class

Technology	2010-2011 Mothball Avoidable Cost Rate ($/MW-Day)	2010-2011 Retirement Avoidable Cost Rate ($/MW-Day)	2011-2012 Mothball Avoidable Cost Rate ($/MW-Day)	2011-2012 Retirement Avoidable Cost Rate ($/MW-Day)	2012-2013 Mothball Avoidable Cost Rate ($/MW-Day)	2012-2013 Retirement Avoidable Cost Rate ($/MW-Day)
CC- 2 on 1 Frame F	$30.92	$43.86	$32.33	$45.85	$33.80	$47.94
CC- 3 on 1 Frame E/Siemens	$34.33	$46.48	$35.89	$48.60	$37.52	$50.81
CC – 3 or More on 1 or More Frame F	$26.76	$37.16	$27.98	$38.85	$29.26	$40.62
CC-NUG Cogen. Frame B or E Technology	$114.93	$154.43	$120.16	$161.45	$125.62	$168.80
CT - 1st & 2nd Gen. Aero (P&W FT 4)	$24.57	$32.68	$25.69	$34.17	$26.86	$35.73
CT - 1st & Gen. Frame B	$24.28	$32.41	$25.38	$33.87	$26.54	$35.42
CT - 2nd Gen. Frame E	$23.08	$30.89	$24.13	$32.29	$25.23	$33.76
CT - 3rd Gen. Aero (GE LM 6000)	$55.87	$82.36	$58.42	$86.10	$61.07	$90.02
CT - 3rd Gen. Aero (P&W FT - 8 TwinPak)	$29.30	$43.20	$30.64	$45.17	$32.03	$47.23
CT - 3rd Gen. Frame F	$23.69	$34.12	$24.77	$35.68	$25.90	$37.30
Diesel	$26.29	$33.39	$27.49	$34.91	$28.74	$36.49
Oil and Gas Steam	$65.21	$79.39	$68.18	$83.01	$71.28	$86.78

After the Market Monitoring Unit conducts its annual review of the table of default Avoided Cost Rates included in section 6.7(c) above in accordance with the procedure specified in section II.H of Attachment M – Appendix, it will provide updated values or notice of its determination that updated values are not needed to Office of the Interconnection. In the event that the Office of the Interconnection disagrees with the values proposed for revising the matrix, the Office of the Interconnection shall file its values.

(d) In order for costs to qualify for inclusion in the Market Seller Offer Cap, the Capacity Market Seller must provide to the Market Monitoring Unit relevant cost data concerning each data item specified as set forth in section 6. If cost data is not available at the time of submission for the time periods specified in section 6.8, costs may be estimated for such period based on the most recent data available, with an explanation of and basis for the estimate used. Based on the data and calculations submitted by the Capacity Market Sellers for each existing generation resource and the formulas specified below, the Market Monitoring Unit shall calculate the Market Seller Offer Cap for each such resource, and notify the Capacity Market Seller one month prior to the auction of its determination.

i. Avoidable Cost Rate: The Avoidable Cost Rate for an existing generation resource shall be determined using the formula below and applied to the unit's Base Offer Segment.

ii. Opportunity Cost: Opportunity Cost shall be the documented price available to an existing generation resource in a market external to PJM. In the event that the total MW of existing generation resources submitting opportunity cost offers in any auction for a Delivery Year exceeds the firm export capability of the PJM system for such Delivery Year, or the capability of external markets to import capacity in such year, the Office of the Interconnection will accept such offers on a competitive basis. PJM will construct a supply curve of opportunity cost offers, ordered by opportunity cost, and accept such offers to export starting with the highest opportunity cost, until the maximum level of such exports is reached. The maximum level of such exports is the lesser of the Office of the Interconnection's ability to permit firm exports or the ability of the importing area(s) to accept firm imports or imports of capacity, taking account of relevant export limitations by location. If, as a result, an opportunity cost offer is not accepted from an existing generation resource, the Market Seller Offer Cap applicable to Sell Offers relying on such generation resource shall be the Avoidable Cost Rate less the Projected Market Revenues for such resource (as defined in Section 6.4). The default Avoidable Cost Rate shall be the one year mothball Avoidable Cost Rate set forth in the tables in section 6.7(c) above unless Capacity Market Seller satisfies the criteria delineated in section 6.7(e) below.

iii. Projected PJM Market Revenues, as defined by section 6.8(d), for any Generation Capacity Resource to which the Avoidable Cost Rate is applied.

(e) In order for the retirement Avoidable Cost Rate set forth in the table in section 6.7(c) to apply, a Capacity Market Seller must timely submit to the Office of the Interconnection and the Market Monitoring Unit a written sworn, notarized statement of a corporate officer representing that the Capacity Market Seller will retire the Generation Capacity Resource if it does not receive during the relevant Delivery Year at least the applicable retirement Avoidable Cost Rate because it would be uneconomic to continue to operate the Generation Capacity Resource in the Delivery Year without the retirement Avoidable Cost Rate, and specifying the date the Generation Capacity Resource would otherwise be retired.

6.8 Avoidable Cost Definition

(a) **Avoidable Cost Rate**:

The Avoidable Cost Rate for a Generation Capacity Resource that is the subject of a Sell Offer shall be determined using the following formula, expressed in dollars per MW-year:

Avoidable Cost Rate = [Adjustment Factor * (AOML + AAE + AME + AVE + ATFI + ACC + ACLE) + ARPIR + APIR]

Where:

- **Adjustment Factor** equals 1.10 (to provide a margin of error for understatement of costs) plus an additional adjustment referencing the 10-year average Handy-Whitman Index in order to account for expected inflation from the time interval between the submission of the Sell Offer and the commencement of the Delivery Year.

- **AOML (Avoidable Operations and Maintenance Labor)** consists of the avoidable labor expenses related directly to operations and maintenance of the generating unit for the twelve months preceding the month in which the data must be provided. The categories of expenses included in AOML are those incurred for: (a) on-site based labor engaged in operations and maintenance activities; (b) off-site based labor engaged in on-site operations and maintenance activities directly related to the generating unit; and (c) off-site based labor engaged in off-site operations and maintenance activities directly related to generating unit equipment removed from the generating unit site.

    - **AAE (Avoidable Administrative Expenses)** consists of the avoidable administrative expenses related directly to employees at the generating unit for twelve months preceding the month in which the data must be provided. The categories of expenses included in AAE are those incurred for: (a) employee expenses (except employee expenses included in AOML); (b) environmental fees; (c) safety and operator training; (d) office supplies; (e) communications; and (f) annual plant test, inspection and analysis.

    - **AME (Avoidable Maintenance Expenses)** consists of avoidable maintenance expenses (other than expenses included in AOML) related directly to the generating unit for the twelve months preceding the month in which the data must be provided. The categories of expenses included in AME are those incurred for: (a) chemical and materials consumed during maintenance of the generating unit; and (b) rented maintenance equipment used to maintain the generating unit.

    - **AVE (Avoidable Variable Expenses)** consists of avoidable variable expenses related directly to the generating unit incurred in the twelve months preceding the month in which the data must be provided. The categories of expenses included in AVE are those incurred for: (a) water treatment chemicals and lubricants; (b) water, gas, and electric service (not for power generation); and (c) waste water treatment.

    - **ATFI (Avoidable Taxes, Fees and Insurance)** consists of avoidable expenses related directly to the generating unit incurred in the twelve months preceding the month in which the data must be provided. The categories of expenses included in AFTI are those incurred for: (a) insurance, (b) permits and licensing fees, (c) site security and utilities for maintaining security at the site; and (d) property taxes.

- **ACC (Avoidable Carrying Charges)** consists of avoidable short-term carrying charges related directly to the generating unit in the twelve months preceding the month in which the data must be provided. Avoidable short-term carrying charges shall include short term carrying charges for maintaining reasonable levels of inventories of fuel and spare parts that result from short-term operational unit decisions as measured by industry best practice standards. For the purpose of determining ACC, short term is the time period in which a reasonable replacement of inventory for normal, expected operations can occur.

- **ACLE (Avoidable Corporate Level Expenses)** consists of avoidable corporate level expenses directly related to the generating unit incurred in the twelve months preceding the month in which the data must be provided. Avoidable corporate level expenses shall include only such expenses that are directly linked to providing tangible services required for the operation of the generating unit proposed for Deactivation. The categories of avoidable expenses included in ACLE are those incurred for: (a) legal services, (b) environmental reporting; and (c) procurement expenses.

- **APIR (Avoidable Project Investment Recovery Rate) = PI * CRF**

Where:

- **PI** is the amount of project investment completed prior to June 1 of the Delivery Year, except for Mandatory Capital Expenditures ("CapEx") for which the project investment must be completed during the Delivery Year, that is reasonably required to enable a Generation Capacity Resource that is the subject of a Sell Offer to continue operating or improve availability during Peak-Hour Periods during the Delivery Year.

- **CRF** is the annual capital recovery factor from the following table, applied in accordance with the terms specified below.

Age of Existing Units (Years)	Remaining Life of Plant (Years)	Levelized CRF
1 to 5	30	0.107
6 to 10	25	0.114
11 to 15	20	0.125
16 to 20	15	0.146
21 to 25	10	0.198
25 Plus	5	0.363
Mandatory CapEx	4	0.450

40 Plus Alternative	1	1.100

Unless otherwise stated, Age of Existing Unit shall be equal to the number of years since the Unit commenced commercial operation, up to and through the relevant Delivery Year.

Remaining Life of Plant defines the amortization schedule (i.e., the maximum number of years over which the Project Investment may be included in the Avoidable Cost Rate.)

Capital Expenditures and Project Investment

For any given Project Investment, a Capacity Market Seller may make a one-time election to recover such investment using: (i) the highest CRF and associated recovery schedule to which it is entitled; or (ii) the next highest CRF and associated recovery schedule. For these purposes, the CRF and recovery schedule for the 25Plus category is the next highest CRF and recovery schedule for both the Mandatory CapEx and the 40 Plus Alternative categories. The Capacity Market Seller using the above table must provide the Market Monitoring Unit with information, identifying and supporting such election, including but not limited to the age of the unit, the amount of the Project Investment, the purpose of the investment, evidence of corporate commitment (e.g., an SEC filing, a press release, or a letter from a duly authorized corporate officer indicating intent to make such investment), and detailed information concerning the governmental requirement (if applicable). Absent other written notification, such election shall be deemed based on the CRF such Seller employs for the first Sell Offer reflecting recovery of any portion of such Project Investment.
For any resource using the CRF and associated recovery schedule from the CRF table that set the Capacity Resource Clearing Price in any Delivery Year, such Capacity Market Seller must also provide to the Market Monitoring Unit, for informational purposes only, evidence of the actual expenditure of the Project Investment, when such information becomes available.

If the project associated with a Project Investment that was included in a Sell Offer using a CRF and associated recovery schedule from the above table has not entered into commercial operation prior to the end of the relevant Delivery Year, and the resource's Sell Offer sets the clearing price for the relevant LDA, the Capacity Market Seller shall be required to elect to either (i) pay a charge that is equal to the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the APIR component of the Avoidable Cost Rate, this difference to be multiplied by the cleared MW volume from such Resource ("rebate payment"); (ii) hold such rebate payment in escrow, to be released to the Capacity Market Seller in the event that the project enters into commercial operation during the subsequent Delivery Year or rebated to LSEs in the relevant LDA if the project has not entered into commercial operation during the subsequent Delivery Year; or (iii) make a reasonable investment in the amount of the PI in other Existing Generation Capacity Resources owned or controlled by the Capacity Market Seller or its Affiliates in the relevant LDA. The revenue from such rebate payments shall be allocated pro rata to LSEs in the relevant LDA(s) that were charged a Locational Reliability Charge for such Delivery Year, based on their Daily Unforced Capacity Obligation in the relevant LDA(s). If the Sell Offer from the Generation Capacity Resource did not set the Capacity Resource Clearing Price in the relevant LDA, no alternative investment or rebate payment is required. If the difference between the

Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the APIR amount does not exceed the greater of $10 per MW-day or a 10% increase in the clearing price, no alternative investment or rebate payment is required.

Mandatory CapEx Option

The Mandatory CapEx CRF and recovery schedule is an option available, beginning in the third BRA (Delivery Year 2009-10), to a resource that must make a Project Investment to comply with a governmental requirement that would otherwise materially impact operating levels during the Delivery Year, where: (i) such resource is a coal, oil or gas-fired resource that began commercial operation no fewer than fifteen years prior to the start of the first Delivery Year for which such recovery is sought, and such Project Investment is equal to or exceeds $200/kW of capitalized project cost; or (ii) such resource is a coal-fired resource located in an LDA for which a separate VRR Curve has been established for the relevant Delivery Years, and began commercial operation at least 50 years prior to the conduct of the relevant BRA.

A Capacity Market Seller that wishes to elect the Mandatory CapEx option for a Project Investment must do so beginning with the Base Residual Auction for the Delivery Year in which such project is expected to enter commercial operation. A Sell Offer submitted in any Base Residual Auction for which the Mandatory CapEx option is selected may not exceed an offer price equivalent to 0.90 times the then-current Net CONE (on an unforced-equivalent basis).

40 Plus Alternative Option

The 40 Plus Alternative CRF and recovery schedule is an option available, beginning in the third BRA (Delivery Year 2009-10), for a resource that is a gas- or oil-fired resource that began commercial operation no less than 40 years prior to the conduct of the relevant BRA (excluding, however, any resource in any Delivery Year for which the resource is receiving a payment under Part V of the PJM Tariff. Generation Capacity Resources electing this 40 Plus Alternative CRF shall be treated as At Risk Generation for purposes of the sensitivity runs in the RTEP process). Resources electing the 40 Plus Alternative option will be modeled in the RTEP process as "at-risk" at the end of the one-year amortization period.

A Capacity Market Seller that wishes to elect the 40 Plus Alternative option for a Project Investment must provide written notice of such election to the Office of the Interconnection no later than six months prior to the Base Residual Auction for which such election is sought; provided however that shorter notice may be provided if unforeseen circumstances give rise to the need to make such election and such seller gives notice as soon as practicable.

The Office of the Interconnection shall give market participants reasonable notice of such election, subject to satisfaction of requirements under the PJM Operating Agreement for protection of confidential and commercially sensitive information. A Sell Offer submitted in any Base Residual Auction for which the 40 Plus Alternative option is selected may not exceed an offer price equivalent to the then-current Net CONE (on an unforced-equivalent basis).

Multi-Year Pricing Option

A Seller submitting a Sell Offer with an APIR component that is based on a Project Investment of at least $450/kW may elect this Multi-Year Pricing Option by providing written notice to such effect the first time it submits a Sell Offer that includes an APIR component for such Project Investment. Such option shall be available on the same terms, and under the same conditions, as are available to Planned Generation Capacity Resources under section 5.14(c) of this Attachment.

- ARPIR (Avoidable Refunds of Project Investment Reimbursements) consists of avoidable refund amounts of Project Investment Reimbursements payable by a Generation Owner to PJM under Part V, Section 118 of this Tariff or avoidable refund amounts of project investment reimbursements payable by a Generation Owner to PJM under a Cost of Service Recovery Rate filed under Part V, Section 119 of the Tariff and approved by the Commission.

(b) For the purpose of determining an Avoidable Cost Rate, avoidable expenses are incremental expenses directly required to operate a Generation Capacity Resource that a Generation Owner would not incur if such generating unit did not operate in the Delivery Year or meet Availability criteria during Peak-Hour Periods during the Delivery Year.

(c) For the purpose of determining an Avoidable Cost Rate, avoidable expenses shall exclude variable costs recoverable under cost-based offers to sell energy from operating capacity on the PJM Interchange Energy Market under the Operating Agreement.

(d) Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied shall include all actual unit-specific revenues from PJM energy markets, ancillary services, and unit-specific bilateral contracts from such Generation Capacity Resource, net of marginal costs for providing such energy (i.e., costs allowed under cost-based offers pursuant to Section 6.4 of Schedule 1 of the Operating Agreement) and ancillary services from such resource.

(i) For the first three BRAs (for Delivery Years 2007-08, 2008-09, 2009-10), the calculation of Projected PJM Market Revenues shall be equal to the simple average of such net revenues as described above for calendar years 2001-2006; and

(ii) For the fourth BRA (delivery year 2010-11) and thereafter, the calculation of Projected PJM Market Revenues shall be equal to the rolling simple average of such net revenues as described above from the three most recent whole calendar years prior to the year in which the BRA is conducted.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because the Generation Capacity Resource was not integrated into PJM

during the full period, then the Projected PJM Market Revenues shall be calculated using only those whole calendar years within the full period in which such Resource received PJM market revenues.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because it was not in commercial operation during the entire period, or if data is not available to the Capacity Market Seller for the entire period, despite the good faith efforts of such seller to obtain such data, then the Projected PJM Market Revenues shall be calculated based upon net revenues received over the entire period by comparable units, to be developed by the MMU and the Capacity Market Seller.

8. CAPACITY RESOURCE DEFICIENCY CHARGE

8.1

A Capacity Resource Deficiency Charge shall be assessed on any Capacity Market Seller that commits a Capacity Resource, and on any Locational UCAP Seller that sells Locational UCAP for a Delivery Year based on a Generation Capacity Resource, for a Delivery Year that is unable or unavailable to deliver Unforced Capacity for all or any part of such Delivery Year for any reason, including but not limited to the following, and that does not obtain replacement Unforced Capacity meeting the same locational requirements and same or better temporal availability characteristics (i.e., Annual Resource, Extended Summer Demand Resource, or Limited Demand Resource) in the megawatt quantity required to satisfy the capacity committed from such resource by such seller as a result of all cleared Sell Offers from such seller based on such resource in any RPM Auctions for such Delivery Year, the reduction in any such commitment for such resource to the extent and for the time period of any replacement capacity committed in lieu of such resource, and the increase in any such commitment for such resource to the extent and for the time period that such resource is committed as replacement capacity for any other resource:

a) Unit Derating – Such Capacity Resource is a Generation Capacity Resource and its capacity value is derated prior to or during the Delivery Year;

b) EFORD Increase – Such Capacity Resource is a Generation Capacity Resource and the EFORD value determined for such resource at least two (2) months prior to the Third Incremental Auction is higher than the EFORD value submitted in the Capacity Market Seller's cleared Sell Offer;

c) External Generation Resource – Such Capacity Resource is an Existing Generation Capacity Resource that is located outside of the PJM Control Area and arrangements for the firm delivery of the output of such resource to the interface with the PJM Region are not in place for such resource prior to the start of the Delivery Year;

d) Planned Generation Resource – Such Capacity Resource is a Planned Generation Capacity Resource and Interconnection Service has not commenced as to such resource prior to the start of the Delivery Year;

e) Planned Demand Resource - Such Capacity Resource is a Planned Demand Resource or an Energy Efficiency Resource and the associated demand response program or energy efficiency measure is not installed prior to the start of the Delivery Year; or

f) Existing Demand Resource – Such Capacity Resource is an existing Demand Resource or Energy Efficiency Resource and, subject to section 8.4, is not capable of providing the megawatt quantity of load response specified in the cleared Sell Offer for the time periods of availability associated with the product type.

8.2. Capacity Resource Deficiency Charge

The Capacity Resource Deficiency Charge shall equal the Daily Deficiency Rate (as defined in section 7) multiplied by the megawatt quantity of deficiency below the level of capacity committed in such Capacity Market Seller's Sell Offer(s) or bilateral capacity commitments, or Locational UCAP Seller's Locational UCAP sale for each day such seller is deficient.

8.3. Allocation of Revenue Collected from Capacity Resource Deficiency Charges

The revenue collected from the assessment of a Capacity Resource Deficiency Charge shall be distributed on a pro-rata basis to all LSEs that were charged a Locational Reliability Charge for the day for which such Capacity Resource Deficiency Charge was assessed. Such revenues shall be distributed on a pro-rata basis to such LSEs based on their Daily Unforced Capacity Obligations.

8.4 Relief from Charges

A Capacity Market Seller or Locational UCAP Seller that is otherwise subject to the Capacity Resource Deficiency Charge solely as a result of section 8.1(f) may receive relief from such Charge if it demonstrates that the inability to provide the level of demand response specified in its Sell Offer is due to the permanent departure (due to plant closure, efficiency gains, or similar reasons) from the Transmission System of load that was relied upon for load response in such Sell Offer; provided, however, that such seller must provide the Office of the Interconnection with all information deemed necessary by the Office of the Interconnection to assess the merits of the request for relief. Such seller shall receive no RPM Auction Credit for the amount of reduction in the committed Existing Demand Resources.

13. EMERGENCY PROCEDURE CHARGE

13.1 Application of the Emergency Procedure Charge

Following an Emergency, the compliance during the period of such Emergency with the instructions of the Office of the Interconnection of: (a) each Capacity Market Seller that committed Capacity Resources, and each Locational UCAP Seller that sold Locational UCAP, for such period; and (b) each ILR Provider responsible for ILR certified for such period, shall be evaluated as recommended by the Markets and Reliability Committee and directed by the PJM Board. If, based on such evaluation, it is determined that a Capacity Market Seller, Locational UCAP Seller, or ILR Provider refused to comply with, or otherwise failed to employ its best efforts to comply with, the instructions of the Office of the Interconnection to implement PJM emergency procedures, then such Capacity Market Seller, Locational UCAP Seller, or ILR Provider shall pay an Emergency Procedure Charge.

13.2 Emergency Procedure Charge

The Emergency Procedure Charge shall equal the number of days in the Delivery Year multiplied by the Daily Deficiency Rate for such Delivery Year times each megawatt of a Demand Resource or ILR that was not implemented as directed, and each megawatt of a Generation Capacity Resource that was not made available as directed despite being capable of producing energy at the time, and that is deliverable to the PJM Region in the case of a Generation Capacity Resource located outside the PJM Region.

13.3 Allocation of Revenue from Emergency Procedure Charges

The revenue collected from assessment of an Emergency Procedure Charge shall be distributed on a pro-rata basis to all LSEs that were charged a Locational Reliability Charge for the day for which the Emergency Procedure Charge was assessed. The charges shall be allocated on a pro-rata basis to all such LSEs based on their Daily Unforced Capacity Obligation.

15. COORDINATION WITH ECONOMIC PLANNING PROCESS

Following each Base Residual Auction, the Office of the Interconnection shall review each LDA that has a Locational Price Adder to determine if Planned Generation Capacity Resources, Planned Demand Resources, or Qualifying Transmission Upgrades submitted Sell Offers that cleared in such auction. If a Locational Price Adder results from the clearing of an LDA for two consecutive Base Residual Auctions, and no such planned resources or upgrades clear in such auctions for such LDA, then the Office of the Interconnection shall evaluate in the RTEP process the costs and benefits of a transmission upgrade that would reduce to zero the Locational Price Adder for such LDA. Such evaluation will compare the cost of the upgrade over ten years against the value of elimination of the Locational Price Adder over such period. If such upgrade is found to be feasible and beneficial, it shall be included in the RTEP as soon as practicable. The annual costs of such upgrade shall be allocated as specified in Schedule 12 of the Tariff and Schedule 6 of the Operating Agreement.

PJM Operating Agreement
(Clean Sections)

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 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) In the Real-time Energy Market, Market Participants that deviate from the amounts of energy purchases or sales, or Transmission Customers that deviate from the transmission uses, scheduled in the Day-ahead Energy Market shall be obligated to purchase or sell energy, or 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.

(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 shall be conducted as specified 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.

1.10.1A Day-ahead Energy Market Scheduling.

The following actions shall occur not later than 12:00 noon 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.

(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 bilateral transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection whether the transaction is to be included in the Day-ahead Energy Market. Any Market Participant that elects to include a bilateral transaction in the Day-ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the PJM Manuals), if any, at which it will be wholly or partially curtailed rather than pay Transmission Congestion Charges. The foregoing price specification shall apply to the price difference between the specified bilateral transaction source and sink points in the day-ahead scheduling process only. Any Market Participant that elects not to include its bilateral 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 Charges in the Real-time Energy Market in order to complete any such scheduled bilateral transaction. Scheduling of bilateral transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

i) Internal Market Buyers shall submit schedules for all bilateral purchases for delivery within the PJM Region, whether from generation resources inside or outside the PJM Region;

ii) Market Sellers shall submit schedules for bilateral sales to entities outside the PJM Region from generation within the PJM Region that is not dynamically scheduled to such entities pursuant to Section 1.12; and

iii) In addition to the foregoing schedules for bilateral transactions, Market Participants shall submit confirmations of each scheduled bilateral

transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(d) Market Sellers wishing to sell into the Day-ahead Energy Market shall submit offers for the supply of energy (including energy from hydropower units), demand reductions, Regulation, Operating Reserves or other services for the following 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(d), Schedule 2 of the Operating Agreement, and the PJM Manuals, as applicable. 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 Attachment DD of the PJM Tariff, 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. The submission of offers for resource increments that have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, and the PJM Manuals, as applicable. Energy offered from generation resources that have not cleared a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff 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 Demand Resource and energy or demand reduction, amount, respectively, for each hour in the offer period, and the minimum run time for generation resources and minimum down time for Demand Resources;

ii) Shall specify the amounts and prices for the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;

iii) If based on energy from a specific generating unit, may specify start-up and no-load fees equal to the specification of such fees for such unit on file with the Office of the Interconnection, if based on reductions in demand from a Demand Resource may specify shutdown costs;

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 a second schedule 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, which offer shall remain open through the Operating Day for which the offer is submitted;

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; and

viii) Shall not exceed an energy offer price of $1,000/megawatt-hour.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation that shall specify the megawatt of Regulation being offered, which must equal or exceed 0.1 megawatts, the Regulation Zone for which such regulation is offered, the price of the offer in dollars per MWh, 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. The price of the offer shall not exceed $100 per MWh in the case of Regulation offered for all Regulation Zones. 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 heat rate increase resulting from operating the unit at lower megawatt output incurred from the provision of Regulation;

ii. The cost increase (in $/MW) in variable operating and maintenance costs resulting from operating the unit at lower megawatt output incurred from the provision of Regulation; and

iii. An adder of up to $12.00 per megawatt of Regulation provided.

Qualified Regulation capability must satisfy the 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 and no-load fees, 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.

(g) Each offer by a Market Seller of a Generation Capacity Resource 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 Increment Bids and/or Decrement Bids that apply to the Day-ahead Energy Market only. Such bids 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 3000 bid/offer segments in the Day-ahead Energy Market, 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 Bid or Decrement Bid.

(j) A Market Seller that wishes to make a generation resource or Demand Resource available to sell Synchronized Reserve shall submit an offer for Synchronized Reserve that shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.1 megawatts, the price of the offer in dollars per megawatt hour, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the energy used by the generation resource to provide the Synchronized Reserve and the generation resource's unit specific opportunity costs. The price of the offer shall not exceed the variable operating and maintenance costs for providing Synchronized Reserve plus seven dollars and fifty cents.

(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. The offer must equal or exceed 0.1 megawatts, and the offer 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; and (iii) at the Economic Load Response Participant's option, start-up 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. 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).

(l) Market Sellers owning or controlling the output of a Demand Resource that was committed in an FRR Capacity Plan, self-supplied or offered and cleared in the Base Residual

Auction or one of the Incremental Auctions, or owning or controlling the output of an ILR resource which was certified as specified in Attachment DD of the PJM Tariff, may submit demand reduction bids for the available load reduction capability of the Demand Resource or ILR resource. The submission of demand reduction bids for resource increments that have not cleared in the Base Residual Auction or in one of the Incremental Auctions, or for ILR resources that were not certified, or were not committed in an FRR Capacity Plan, shall be optional, but any such bids must contain the information specified in the PJM Economic Load Response Program to be included in such bids. A Demand Resource that was committed in an FRR Capacity Plan, self-supplied or offered and cleared in a Base Residual Auction or an 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 Demand Resources and ILR 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) Market Sellers that wish to make Day-ahead Scheduling Reserves Resources available to sell Day-ahead Scheduling Reserves shall submit offers, each of which must equal or exceed 0.1 megawatts, in the Day-ahead Scheduling Reserves Market specifying: 1) the price of the offer in dollars per megawatt hour; and 2) such other information specified by the Office of the Interconnection as may be necessary to determine any relevant opportunity costs for the resource(s). The foregoing notwithstanding, to qualify to submit offers pursuant to this section, the Day-ahead Scheduling Reserves Resources shall submit energy offers in the Day-ahead Energy Market including start-up and shut-down costs for generation resource and Demand Resources, respectively, and all generation resources that are capable of providing Day-ahead Scheduling Reserves that a particular resource can provide that service. The MW quantity of Day-ahead Scheduling Reserves that a particular resource can provide in a given hour will be determined based on the energy offer data submitted in the Day-ahead Energy Market, as detailed in the PJM Manuals.

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 Sections 1.10.9 or 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, start-up, no-load 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.

(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 and no-load fees, from the Office of the Interconnection on behalf of the Market Buyers in accordance with Section 3 of this Schedule 1. Alternatively, the Market Seller shall receive, in lieu of start-up and no-load fees, its actual costs incurred, if any, up to a cap of the resource's start-up cost, 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 offer must equal or exceed 0.1 megawatts, in minimum increments of .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 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, or otherwise not following the dispatch orders of 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.

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.

(c) A resource that has been self-scheduled shall not receive payments or credits for start-up or no-load fees.

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 dispatch 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 dispatch 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.

1.10.6A Transmission Loading Relief Customers.

(a) An entity that desires to elect to pay Transmission Congestion Charges in order to continue its energy schedules during an Operating Day over contract paths outside the PJM Region in the event that PJM initiates Transmission Loading Relief that otherwise would cause PJM to request security coordinators to curtail such Member's energy schedules shall:

(i) enter its election on OASIS by 12:00 p.m. of the day before the Operating Day, in accordance with procedures established by PJM, which election shall be applicable for the entire Operating Day; and

(ii) if PJM initiates Transmission Loading Relief, provide to PJM, at such time and in accordance with procedures established by PJM, the hourly

integrated energy schedules that impacted the PJM Region (as indicated from the NERC Interchange Distribution Calculator) during the Transmission Loading Relief.

(b) If an entity has made the election specified in Section (a), then PJM shall not request security coordinators to curtail such entity's energy transactions, except as may be necessary to respond to Emergencies.

(c) In order to make elections under this Section 1.10.6A, an entity must (i) have met the creditworthiness standards established by the Office of the Interconnection or provided a letter of credit or other form of security acceptable to the Office of the Interconnection, and (ii) have executed either the Agreement, a Service Agreement under the PJM Tariff, or other agreement committing to pay all Transmission Congestion Charges incurred under this Section.

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 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; (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 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) Not earlier than 4:00 p.m. 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.

(c) Following posting of the information specified in Section 1.10.8(b), 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 offer that set 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 offer that set the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Section 3.3A of this Schedule.

(e) If the Office of the Interconnection discovers an error in prices and/or cleared quantities in the Day-ahead Energy Market, Real-time Energy Market, Ancillary Services Markets or Day Ahead Scheduling Reserve Market after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants of the error 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 Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the second business day following the initial publication of the results for the Day-ahead Scheduling Reserve Market and Day-ahead Energy Market. 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, together with all available supporting documentation, by no later than 5:00 p.m. of the fifth business day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the fifth business day following the initial publication of the results in the Day-ahead Scheduling Reserve Market and the Day-ahead Energy Market. 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 Ancillary Services Markets, Day-ahead Energy Market and Real-time Energy Market, and no later than 5:00 p.m. of the tenth calendar day following the initial publication of the results in the Day-ahead Scheduling Reserve Market. 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 Section 18.17.1 of the PJM Operating Agreement, 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, a generation rebidding period shall exist from 4:00 p.m. to 6:00 p.m. on the day before each Operating Day. During the rebidding period, Market Participants may submit revisions to generation Offer Data for any generation resource that was not selected as a pool-scheduled resource in the Day-ahead Energy Market. Adjustments to Day-ahead Energy Markets 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 10:00 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 60 minutes prior to the hour in which the adjustment is to take effect, as follows:

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 fee.

(c) With respect to a pool-scheduled resource that is included in the Day-ahead Energy Market, a Market Seller may not change or otherwise modify its offer to sell energy.

(d) 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 60 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.

(e) 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.

1.11 Dispatch.

The following procedures and principles shall govern the dispatch of the resources available to the Office of the Interconnection.

1.11.1 Resource Output.

The Office of the Interconnection shall have the authority to direct any Market Seller to adjust the output of any pool-scheduled resource increment within the operating characteristics specified in the Market Seller's offer. The Office of the Interconnection may cancel its selection of, or otherwise release, pool-scheduled resources, subject to an obligation to pay any applicable start-up, no-load or cancellation fees. The Office of the Interconnection shall adjust the output of pool-scheduled resource increments as necessary: (a) to maintain reliability, and subject to that constraint, to minimize the cost of supplying the energy, reserves, and other services required by the Market Buyers and the operation of the PJM Region; (b) to balance load and generation, maintain scheduled tie flows, and provide frequency support within the PJM Region; and (c) to minimize unscheduled interchange not frequency related between the PJM Region and other Control Areas.

1.11.2 Operating Basis.

In carrying out the foregoing objectives, the Office of the Interconnection shall conduct the operation of the PJM Region in accordance with the PJM Manuals, and shall: (i) utilize available generating reserves and obtain required replacements; and (ii) monitor the availability of adequate reserves.

1.11.3 Pool-dispatched Resources.

(a) The Office of the Interconnection shall implement the dispatch of energy from pool-scheduled resources with limited energy by direct request. In implementing mandatory or economic use of limited energy resources, the Office of the Interconnection shall use its best efforts to select the most economic hours of operation for limited energy resources, in order to make optimal use of such resources consistent with the dynamic load-following requirements of the PJM Region and the availability of other resources to the Office of the Interconnection.

(b) The Office of the Interconnection shall implement the dispatch of energy from other pool-dispatched resource increments, including generation increments from Capacity Resources the remaining increments of which are self-scheduled, by sending appropriate signals and instructions to the entity controlling such resources, in accordance with the PJM Manuals. Each Market Seller shall ensure that the entity controlling a pool-dispatched resource offered or made available by that Market Seller complies with the energy dispatch signals and instructions transmitted by the Office of the Interconnection.

1.11.3A Maximum Generation Emergency.

If the Office of the Interconnection declares a Maximum Generation Emergency, all deliveries to load that is served by Point-to-Point Transmission Service outside the PJM Region from Generation Capacity Resources committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative may be interrupted in order to serve load in the PJM Region.

1.11.4 Regulation.

(a) A Market Buyer may satisfy its Regulation Obligation from its own generation resources and/or Demand Resources capable of performing Regulation service, by contractual arrangements with other Market Participants able to provide Regulation service, or by purchases from the PJM Interchange Energy Market at the rates set forth in Section 3.2.2. PJMSettlement shall be the Counterparty to the purchases and sales of Regulation service in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Regulation Obligation.

(b) The Office of the Interconnection shall obtain Regulation service from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Demand Resources as needed to meet Regulation Zone requirements not otherwise satisfied by the Market Buyers. Generation resources or Demand Resources offering to sell Regulation shall be selected to provide Regulation on the basis of each generation resource's and Demand Resource's regulation offer and the estimated opportunity cost of a resource providing regulation and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Regulation, and other ancillary services. Estimated opportunity costs for generation resources shall be determined by the Office of the Interconnection on the basis of the expected value of the energy sales that would be foregone or uneconomic energy that would be produced by the resource in order to provide Regulation, in accordance with procedures specified in the PJM Manuals. Estimated opportunity costs for Demand Resources will be zero.

(c) The Office of the Interconnection shall dispatch resources for Regulation by sending Regulation signals and instructions to generation resources and/or Demand Resources from which Regulation service has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall comply with Regulation dispatch signals and instructions transmitted by the Office of the Interconnection and, in the event of conflict, Regulation dispatch signals and instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their resources supplying load in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.4A Synchronized Reserve.

(a) A Market Buyer may satisfy its Synchronized Reserve Obligation from its own generation resources and/or Demand Resources capable of providing Synchronized Reserve, by contractual arrangements with other Market Participants able to provide Synchronized Reserve,

or by purchases from the PJM Synchronized Reserve Market at the rates set forth in Section 3.2.3A. PJMSettlement shall be the Counterparty to the purchases and sales of Synchronized Reserve in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Synchronized Reserve Obligation.

(b) The Office of the Interconnection shall obtain Synchronized Reserve from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Demand Resources as needed to meet the Synchronized Reserve requirements of each Synchronized Reserve Zone of the PJM Region not otherwise satisfied by the Market Buyers. Resources offering to sell Synchronized Reserve shall be selected to provide Synchronized Reserve on the basis of each generation resource's and/or Demand Resource's Synchronized Reserve offer and the estimated unit specific opportunity cost of the resource providing Synchronized Reserve, and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Synchronized Reserve and other ancillary services. Estimated unit specific opportunity costs for generation resources shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the generation resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to 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, times (B) the absolute value of 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 Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources will be zero.

(c) The Office of the Interconnection shall dispatch generation resources and/or Demand Resources for Synchronized Reserve by sending Synchronized Reserve instructions to generation resources and/or Demand Resources from which Synchronized Reserve has been offered by Market Sellers, in accordance with the PJM Manuals. Market Sellers shall comply with Synchronized Reserve dispatch instructions transmitted by the Office of the Interconnection and, in the event of a conflict, Synchronized Reserve dispatch instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their generation resources supplying load in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.

1.11.5 PJM Open Access Same-time Information System.

The Office of the Interconnection shall update the information posted on the PJM Open Access Same-time Information System to reflect its dispatch of generation resources.

3.2 Market Buyers.

3.2.1 Spot Market Energy Charges.

(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 Section 2 of this Schedule.

(b) Market Buyers shall be charged for all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(c) Generating Market Buyers shall be paid for all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead System Energy Price.

(d) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the total amount of net hourly PJM Interchange for each Market Buyer, including Generating Market Buyers, in accordance with the PJM Manuals. For Internal Market Buyers that are Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall include determination of the net energy flows from: (i) tie lines; (ii) any generation resource the output of which is controlled by the Market Buyer but delivered to it over another entity's Transmission Facilities; (iii) any generation resource the output of which is controlled by another entity but which is directly interconnected with the Market Buyer's transmission system; (iv) deliveries pursuant to bilateral energy sales; (v) receipts pursuant to bilateral energy purchases; and (vi) an adjustment to account for the day-ahead PJM Interchange, calculated as the difference between scheduled withdrawals and injections by that Market Buyer in the Day-ahead Energy Market. For External Market Buyers and Internal Market Buyers that are not Load Serving Entities or purchasing on behalf of Load Serving Entities, this calculation shall determine the energy scheduled hourly for delivery to the Market Buyer net of the amounts scheduled by such Market Buyer in the Day-ahead Energy Market.

(e) An Internal Market Buyer shall be charged for Spot Market Energy purchases to the extent of its hourly net purchases from the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. An External Market Buyer shall be charged for its Spot Market Energy purchases based on the energy delivered to it, determined as specified in Section 3.2.1(d) above. The total charge shall be determined by the product of the hourly net amount of PJM Interchange Imports times the hourly Real-time System Energy Price for that Market Buyer.

(f) A Generating Market Buyer shall be paid as a Market Seller for sales of Spot Market Energy to the extent of its hourly net sales into the PJM Interchange Energy Market, determined as specified in Section 3.2.1(d) above. The total payment shall be determined by the product of the hourly net amount of PJM Interchange Exports times the hourly Real-time System Energy Price for that Market Seller.

3.2.2 Regulation.

(a) Each Internal Market Buyer 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 requirements of such Regulation Zone for the hour, based on the Market Buyer'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"). An Internal Market Buyer that does not meet its hourly Regulation obligation shall be charged for Regulation dispatched by the Office of the Interconnection to meet such obligation at the Regulation market-clearing price determined in accordance with subsection (c) of this Section, plus the amounts, if any, described in subsection (f) of this section.

(b) A Generating Market Buyer supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection in excess of its hourly Regulation obligation shall be credited for each increment of such Regulation at the higher of (i) the Regulation market-clearing price in such Regulation Zone or (ii) the sum of the regulation offer and the unit-specific opportunity cost of the generation resource supplying the increment of Regulation, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Regulation market-clearing price in each Regulation Zone shall be determined at a time to be determined by the Office of the Interconnection which shall be no earlier than the day before the Operating Day. The market-clearing price for each regulating hour shall be equal to the highest sum of a resource's Regulation offer plus its estimated unit-specific opportunity costs, determined as described in subsection (d) below from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.3.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation market-clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour shall be equal to the sum of the unit-specific opportunity costs (i) incurred during the hour in which the obligation is fulfilled, plus costs (ii) associated with uneconomic operation during the hour preceding the initial regulating hour ("preceding shoulder hour"), plus costs (iii) associated with uneconomic operation during the hour after the final regulating hour ("following shoulder hour").

The unit-specific opportunity costs incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour 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 hour in order to provide Regulation and the lesser of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, 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 the following shoulder hour 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 hour in order to provide Regulation and the lesser of the resource's actual or expected output in the following shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the following shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market.

Estimated opportunity costs for Demand Resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Generating Market Buyer 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 each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's Regulation signals from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the

resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour 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 hour in order to provide Regulation and the lesser of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, 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 the following shoulder hour 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 hour in order to provide Regulation and the lesser of the resource's actual or expected output in the following shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the following shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the following shoulder hour during which the deviation was incurred, 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 Internal Market Buyer 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.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal

supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to section 1.10.1A(e) of this Schedule. A Regulation supplier fails the three-pivotal supplier test in any hour 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 three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region for which the cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The 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.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the prices offered 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 Section 3.2.3A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, 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 Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load fees 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. Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. 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 from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), 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.

(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 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 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 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 in the Day-ahead Energy Market.

(d) The cost of Operating Reserves 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 (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; 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 dynamically scheduled to load outside such area pursuant to Section 1.12.

(e) 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 or minimum run time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or minimum run time (minimum down time for Demand 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 (minimum down time for Demand Resources) and Segment 2 will include the remainder of the contiguous hours 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.

Credits received pursuant to this section shall be equal to the positive difference between a resource's total offered price for start-up (shutdown costs for Demand Resources) and no-load fees and energy, determined on the basis of the resource's scheduled output, and the total value of the resource's energy as determined by the Real-time Energy Market and 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 Demand 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) plus the resource's opportunity cost and less any amounts credited for Synchronized Reserve in excess of the Synchronized Reserve offer plus the resource's opportunity cost and less any amounts credited for providing Reactive Services as specified in Section 3.2.3B, and less any amounts for Day-ahead Scheduling Reserve in excess of the Day-ahead Scheduling Reserve offer plus the resource's opportunity cost, shall be credited to the Market Seller.

Synchronized Reserve and Day-ahead Scheduling Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding hour(s) in which the Synchronized Reserve and Day-ahead Scheduling Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each hour the unit operates in condensing and generation mode .

(f) A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool scheduled (or self-scheduled, if operating according to 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 hourly integrated, 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 hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

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 hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

AG equals the actual hourly integrated output of the unit;

URTLMP equals the real time LMP at the unit's bus;

UB equals the unit offer for that unit for which output is reduced or suspended, determined according to the real-time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for

the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UB shall not be negative.

(f-1) A Market Seller's combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost 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 above for a steam unit or combined cycle unit operating in combined cycle mode.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG}, or (ii) {(URTLMP – UB) x DAG} where:

URTLMP equals the real time LMP at the unit's bus;

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit, determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

(f-2) A Market Seller's hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to 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.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with 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, less any payments received from another Control Area for Operating Reserves, plus any redispatch costs incurred in accordance with section 10(a) of this Schedule, shall be 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 shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (i) load deviations (net of operating Behind The Meter Generation) from the Day-ahead Energy Market in megawatt-hours during that Operating Day; (ii) generation deviations (not including deviations in Behind The Meter Generation) from the Day-ahead Energy Market for non-dispatchable generation resources, including External Resources, in megawatt-hours during the Operating Day; (iii) deviations from the Day-ahead Energy Market for bilateral transactions from outside the PJM Region for delivery within such region in megawatt-hours during the Operating Day, except as noted below and in the PJM Manuals; and (iv) deviations of energy sales from the Day-ahead Energy Market 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 dynamically scheduled to load outside such region pursuant to Section 1.12.

Deviations that occur within a single Zone shall be associated with the Eastern or Western Region, as defined in Section 3.2.3(q) of this Schedule, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with Section 3.2.3(q). Deviations at interfaces and hubs shall be associated with the Eastern or Western Region if all the busses that define all interfaces or all hubs are located in the region. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to 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 busses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed 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 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 an Operating Reserve shortage in real-time or where PJM initiates the request for load reductions in real-time in order to avoid an Operating Reserve shortage as described in this Schedule, Section 6A, Scarcity Pricing.

(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.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized 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 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 for synchronous condensing for the PJM Region for purposes other than providing Synchronized 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 for synchronous condensing for purposes other than providing Synchronized 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 (net of operating Behind The Meter Generation, but not to be less than zero) 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 dynamically scheduled to load outside the PJM Region pursuant to 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 credit otherwise provided by Section 3.2.3.(b) or Section 3.2.3(e) in connection with marked-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 Schedule 2 of the Operating Agreement, 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 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 Section 1.9.7(b); provided, however, that the Market Seller must return to compliance with 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, the Market Seller shall not receive any credit for Operating Reserves. 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 for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatt hours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours 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 hours 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 12:00 noon 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 not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon 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 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 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 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 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 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 generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described in the PJM Manuals. Ramp-limited desired MW values shall be used to determine generation resource real-time deviations from the resource's day-ahead schedules.

The Office of the Interconnection shall calculate a ramp-limited desired MW value for 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:

$$Ramp\_Request_t = \frac{(UDStarget_{t-1} - AOutput_{t-1})}{(UDSLAtime_{t-1})}$$

$$RL\_Desired_t = AOutput_{t-1} + \left(Ramp\_Request_t * Case\_Eff\_time_{t-1}\right)$$

where:

1. UDStarget = UDS basepoint for the previous UDS case
2. AOutput = Unit's output at case solution time
3. UDSLAtime = UDS look ahead time
4. Case_Eff_time = Time between base point changes
5. RL_Desired = Ramp-limited desired MW

To determine if a 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 UDS Basepoint or the actual output and ramp-limited desired MW value. The % off dispatch and MW off dispatch will be a time-weighted average over the course of an hour. If the UDS Basepoint and the ramp-limited desired MW for the resource are unavailable, the Office of Interconnection will determine the unit's MWoff dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the UDS LMP Desired MW.

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 UDS Basepoint, or if its % off dispatch is <= 10, or it's hourly integrated Real-time MWh is within 5% or 5 MW (whichever is greater) of the hourly integrated 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 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: hourly integrated Real-time 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: hourly integrated Real-time MWh – UDS LMP Desired MW.

- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: hourly integrated Real-time MWh – hourly integrated 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 UDS LMP Desired MWh for the hour 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: hourly integrated Real time MWh – UDS 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: hourly integrated Real-time Mwh – hourly integrated Ramp-Limited Desired MW. If deviation value is within 5% or 5 MW (whichever is greater) 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: hourly integrated Real time MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch, and the resource has tripped, for the hour the resource tripped and the hours it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: hourly integrated Real time 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: hourly integrated Real-time MWh and Day-Ahead MWh.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve 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 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 Operating Reserve charges shall be allocated to real-time deviations 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 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 Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing 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 Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed 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 charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category 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(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) 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 Region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, *DEOK* transmission Zones, and the Eastern 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:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve 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 reliability 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 Section 3.2.3(p).

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. 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 Section 3.2.3(p).

(iii) Reliability and deviation regional balancing Operating Reserve rates shall be determined by summing the relevant RTO balancing Operating Reserve 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.

3.2.3A Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Synchronized Reserve Zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Synchronized Reserve 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). An Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts if any, described in subsections (g), (h) and (i) of this section.

(b) A Generating Market Buyer supplying Synchronized Reserve at the direction of the Office of the Interconnection, in excess of its hourly Synchronized Reserve Obligation, shall be credited as follows:

i) Credits for Synchronized Reserve provided by generation units that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event ("Tier 1 Synchronized Reserve") shall be at the Synchronized Energy Premium Price.

ii) Credits for Synchronized Reserve provided by generation resources that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the Interconnection energy dispatch signals and instructions ("Tier 2 Synchronized Reserve") shall be the higher of (i) the Synchronized Reserve Market Clearing Price or (ii) the sum of (A) the Synchronized Reserve offer, and (B) the specific 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.

iii) Credits for Synchronized Reserve provided by Demand Resources that are synchronized to the grid and accept the obligation to reduce load in response to a Synchronized Reserve Event initiated by the Office of the Interconnection shall be the sum of (i) the higher of (A) the synchronized Reserve offer or (B) the Synchronized Reserve Market Clearing Price and (ii) if a Synchronized Reserve Event is actually initiated by the Office of the Interconnection and the Demand Resource reduced its load in response to the event, the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

(c) The Synchronized Reserve Energy Premium Price is the average of the five-minute Locational Marginal Prices calculated during the Synchronized Reserve Event plus an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Synchronized Reserve Zone by the Office of the Interconnection prior to the operating hour and such market-clearing price shall be equal to, from among the generation resources or Demand Resources selected to provide Synchronized Reserve for such Synchronized Reserve Zone, the highest sum of either (i) a generation resource's Synchronized Reserve offer and opportunity cost or (ii) a demand response resource's Synchronized Reserve offer.

(e) In determining the Synchronized Reserve Market Clearing Price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the expected Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) of the difference between the expected 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 Synchronized Reserve set 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. The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to 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, times (B) of 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 Synchronized Reserve set point for the generation 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. The opportunity costs for a Demand Resource shall be zero.

(g) Charges for Tier 1 Synchronized Reserve will be allocated in proportion to the amount of Tier 1 Synchronized Reserve applied to each Synchronized Reserve Obligation. In the event Tier 1 Synchronized Reserve is provided by a Market Seller in excess of that Market Seller's Synchronized Reserve Obligation, the remainder of the Tier 1 Synchronized Reserve that is not utilized to fulfill the Seller's obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

(h) Any amounts credited for Tier 2 Synchronized Reserve in an hour in excess of the Synchronized Reserve Market Clearing Price in that hour shall be allocated and charged to each Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation in proportion to its purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) In the event the Office of the Interconnection needs to assign more Tier 2 Synchronized Reserve during an hour than was estimated as needed at the time the Synchronized Reserve Market Clearing Price was calculated for that hour due to a reduction in available Tier 1 Synchronized Reserve, the costs of the excess Tier 2 Synchronized Reserve shall be allocated and charged to those providers of Tier 1 Synchronized Reserve whose available Tier 1 Synchronized Reserve was reduced from the needed amount estimated during the Synchronized Reserve Market Clearing Price calculation, in proportion to the amount of the reduction in Tier 1 Synchronized Reserve availability.

(j) In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled by the owner to provide Tier 2 Synchronized Reserve fails to provide the assigned or self-scheduled amount of Synchronized Reserve in response to an actual Synchronized Reserve Event, the owner of the resource shall incur an additional Synchronized Reserve Obligation in the amount of the shortfall for a period of three consecutive days with the same peak classification (on-peak or off-peak) as the day of the Synchronized Reserve Event at least three business days following the Synchronized Reserve Event. The overall Synchronized Reserve requirement for each Synchronized Reserve Zone of the PJM Region on which the Synchronized Reserve Obligations, except for the additional obligations set forth in this section, are based shall be reduced by the amount of this shortfall for the applicable three-day period.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l), is the difference between the generation resource's output or the Demand Resource's consumption at the start of the event and its output or consumption ten minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Demand Resource consumption at the start of the event is defined as the lowest telemetered

generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand 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 a Demand Resource will be reduced by the amount the megawatt consumption of the Demand 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 Demand 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 Demand Resource's consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Demand 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.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJMSettlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

(b) A Day-ahead Scheduling Reserves Resource that receives a Day-ahead Scheduling Reserves schedule pursuant to subsection (a) of this section shall be paid the hourly Day-ahead Scheduling Reserves Market clearing price for the MW obligation in each hour of the schedule, subject to meeting the requirements of subsection (c) of this section.

(c) To be eligible for payment pursuant to subsection (b) of this section, Day-ahead Scheduling Reserves Resources shall comply with the following provisions:

(i) Generation resources with a start time greater than thirty minutes are required to be synchronized and operating at the direction of the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule and shall have a dispatchable range equal to or greater than the Day-ahead Scheduling Reserves schedule.

(ii) Generation resources and Demand Resources with start times or shut-down times, respectively, equal to or less than 30 minutes are required to respond to dispatch directives from the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule. To meet this requirement the resource shall be required to start or shut down within the specified notification time plus its start or shut down time, provided that such time shall be less than thirty minutes.

(iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). 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 one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand 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 time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand 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 credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

Resources that do not comply with the provisions of this subsection (c) shall not be eligible to receive credits pursuant to subsection (b) of this section.

(d) The cost of credits allocated to Day-ahead Scheduling Reserves Resources pursuant to this section shall be charged to Load-Serving Entities in the PJM Region based on load ratio share (net of operating Behind The Meter Generation, but not to be less than zero), provided that a Load-Serving Entity may satisfy its Day-ahead Scheduling Reserves obligation, which is equal to the Day-ahead Scheduling Reserves Requirement multiplied by the Load-Serving Entity's load ratio share for the PJM Region, through one or any combination of the following: 1) the Day-ahead Scheduling Reserves Market; 2) and bilateral arrangements. The Day-ahead Scheduling Reserve charges allocated pursuant to this section shall reflect any portion of a Load-Serving Entity's Day-ahead Scheduling Reserves obligation that is met by bilateral arrangement(s).

(e) If the Day-ahead Scheduling Reserves Requirement is not satisfied through the operation of subsection (a) of this section, any additional Operating Reserves required to meet the requirement shall be scheduled by the Office of the Interconnection pursuant to Section 3.2.3 of Schedule 1 of this Agreement.

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 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 either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, 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 hourly in an amount equal to {(LMPDMW - AG) x (URTLMP - UB)}

where:

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 hourly integrated real time LMP;

AG equals the actual hourly integrated output of the unit;

URTLMP equals the real time LMP at the unit's bus;

UB equals the unit offer for that unit for which output is reduced or suspended determined according to the real time scheduled offer curve on which the unit was operating, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UB shall not be negative.

(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 Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost 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 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.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG, or (ii) {(URTLMP – UB) x DAG where:

URTLMP equals the real time LMP at the unit's bus;

UDALMP equals the day-ahead LMP at the unit's bus;

DAG equals the day-ahead scheduled unit output for the hour;

UB equals the offer price for the unit determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

where URTLMP - UDALMP and URTLMP – UB shall not be negative.

(e) At the end of each Operating Day, where the active energy 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).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is 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 hourly in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual hourly integrated output of the unit;

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 hourly integrated real time LMP at the unit's bus and adjusted for any regulation or Tier 2 Synchronized Reserve assignments;

UB equals the unit offer for that unit for which output is increased, determined according to the real time scheduled offer curve on which the unit was operating;

URTLMP equals the real time LMP at the unit's bus; and

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to 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, 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 lost 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 lost opportunity cost compensation, the Office of Interconnection shall invoice the Market Seller

accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost 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 generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 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 hourly Synchronized Reserve Market Clearing Price for each hour 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 generating unit's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generation unit's bus, (C) the generation unit's startup-cost of providing synchronous condensing, and (D) 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 to provide Reactive Services 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 (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 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. 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 (net of operating Behind The Meter Generation) 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 PJM 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 Tier 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 hourly Synchronized Reserve Market Clearing Price for each hour 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 generation resource's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) 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 (net of operating Behind The Meter Generation) 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 Section 5 of this Schedule.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Section 5 of this Schedule.

3.2.6 Emergency Energy.

(a) 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 hour of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange 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.

(b) 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 hour of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net PJM Interchange 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.

(c) The net costs or net revenues associated with sales or purchases of hourly energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each hour 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 PJM Interchange 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 Buyer in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market Buyer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Buyer's internal accounting.

(b) If deliveries to a Market Buyer that has PJM Interchange meters in accordance with Section 14 of the Operating Agreement include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market Buyer, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market Buyer and the unmetered Market Participant specified by them to the Office of the Interconnection.

3.3 Market Sellers.

Except as provided in the following sentence, the accounting and billing principles and procedures applicable to Generating Market Buyers functioning as Market Sellers shall be as set forth in Section 3.2. This Section sets forth the accounting and billing principles and procedures applicable to all other Market Sellers, and to Generating Market Buyers functioning as Market Sellers with respect to any matters not specified in Section 3.2.

3.3.1 Spot Market Energy Charges.

(a) Market Sellers shall be paid for all energy scheduled to be delivered in the Day-ahead Energy Market at the Day-ahead System Energy Prices.

(b) At the end of each hour during an Operating Day, the Office of the Interconnection shall determine the total net amount of energy delivered in the hour to the PJM Region by each of the Market Seller's resources, in accordance with the PJM Manuals and the calculation described in Section 3.2.1(f).

(c) The Office of the Interconnection shall calculate Day-ahead and Real-time System Energy Prices for the PJM Region, in accordance with Section 2 of this Schedule.

(d) A Market Seller shall be paid for real-time sales of Spot Market Energy to the extent of its hourly net deliveries to the PJM Region of energy in excess of amounts scheduled in the Day-ahead Energy Market from the Market Seller's resources. For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the hourly amounts delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region. The total real-time generation revenues for each Market Seller shall be the sum of its payments determined by the product of (i) the hourly net amount of energy delivered to the PJM Region in excess of the amount scheduled to be delivered in that hour in the Day-ahead Energy Market from each of the Market Seller's resources, times (ii) the hourly Real-time System Energy Price. To the extent that the energy actually injected in any hour is less than the energy scheduled to be injected in the Day-ahead Energy Market, the Market Seller shall be debited for the difference at the Real-time System Energy Price at the time of the shortfall times the amount of the shortfall. The total generation revenue for each Market Seller shall be the sum of the revenues at Day-ahead System Energy Prices determined in accordance with the Day-ahead Energy Market as specified in Section 3.3.1(a) plus the revenues at Real-time System Energy Prices determined as specified herein, net of any debits specified herein for each Market Seller.

3.3.2 Regulation.

Each Market Seller that is also an Internal Market Buyer as to load in a Regulation Zone shall have an hourly Regulation objective and shall be credited or charged in connection therewith as specified in Section 3.2.2. All other Market Sellers supplying Regulation in such Regulation Zone at the direction of the Office of the Interconnection shall be credited for each increment of

such Regulation at the price specified in Section 3.2.2(b), as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

3.3.3 Operating Reserves.

A Market Seller shall be credited for its pool-scheduled resources based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource, in accordance with the procedures set forth in Section 3.2.3.

3.3.4 Emergency Energy.

The net costs or net revenues associated with purchases or sales of energy in connection with Emergencies in the PJM Region, or in another Control Area, shall be allocated to Market Participants in accordance with the procedures set forth in Section 3.2.6.

3.3.5 Synchronized Reserve.

Each Market Seller that is also an Internal Market Buyer shall have an hourly Synchronized Reserve objective and shall be credited or charged in connection therewith as specified in Section 3.2.3A(a). All other Market Sellers supplying Synchronized Reserve at the direction of the Office of the Interconnection shall be credited for each increment of such Synchronized Reserve at the price specified in Section 3.2.3A(b), as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

3.3.6 Billing.

PJMSettlement shall prepare a billing statement each billing cycle for each Market Seller in accordance with the charges and credits specified in Sections 3.3.1 through 3.3.5 of this Schedule, and showing the net amount to be paid or received by the Market Seller. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Seller's internal accounting.

5.1 Transmission Congestion Charge Calculation.

5.1.1 Calculation by Office of the Interconnection.

When the transmission system is operating under constrained conditions, or as necessary to provide third-party transmission provider losses , the Office of the Interconnection shall calculate Transmission Congestion Charges for each Network Service User, Market Participants in the PJM Interchange Energy Market, and each Transmission Customer.

5.1.2 General.

The Office of the Interconnection shall calculate Congestion Prices in the form of Day-ahead Congestion Prices and Real-time Congestion Prices for the PJM Region, in accordance with Section 2 of this Schedule.

5.1.3 Network Service User Calculation.

(a) Each Network Service User shall be charged for the increased cost of energy incurred by it during each constrained hour to deliver the output of its firm Generation Capacity Resources or other owned or contracted for resources, its firm bilateral purchases, and its non-firm bilateral purchases as to which it has elected to pay Transmission Congestion Charges.

(b) Market Buyers shall be charged for transmission congestion resulting from all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant load bus.

(c) Generating Market Buyers shall be reimbursed for transmission congestion resulting from all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant generation bus.

(d) Market Sellers shall be reimbursed for transmission congestion resulting from all energy scheduled to be delivered in the Day-ahead Energy Market at the Day-ahead Congestion Prices applicable to each relevant generation bus.

(e) The hourly net amount of energy delivered at each generation bus is determined by revenue meter data if available, or by the State Estimator, if revenue meter data is not available. The total load actually served at each load bus is initially determined by the State Estimator. For each Electric Distributor that reports hourly net energy flows from metered tie lines and for which all generators within the Electric Distributor's territory report revenue quality, hourly net energy delivered, the total revenue meter load within the Electric Distributor's territory is calculated as the sum of all net import energy flows reported by their tie revenue meters and all net generation reported via generator revenue meters. The amount of load at each of such Electric Distributor's load buses calculated by the State Estimator is then adjusted, in proportion to its share of the total load of that Electric Distributor, in order that the total amount of load across all of the Electric Distributor's load buses matches its total revenue meter calculated load.

(f) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the Transmission Congestion Charges at each Market Buyer's load bus to be charged for congestion at Real-time Congestion Prices determined by the product of the hourly Real-time Congestion Price at the relevant bus times the Market Buyer's megawatts of load (net of operating Behind The Meter Generation, but not to be less than zero) at the bus in that hour in excess of the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the hour in the Day-ahead Energy Market. To the extent that the load (net of operating Behind The Meter Generation, but not to be less than zero) actually served at a load bus is less than the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the Day-ahead Energy Market, the Market Buyer shall be paid for the difference at the Real-time Congestion Price for the load bus at the time of the shortfall. The megawatts of load at each load bus shall be the sum of the megawatts of load (net of operating Behind The Meter Generation, but not less than zero) for that bus of that Market Buyer plus any megawatts of that Market Buyer's bilateral sales attributable to that bus. The total load charge for each Market Buyer shall be the sum, for each of a Market Buyer's load buses, of the charges at Day-ahead Congestion Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1a plus the charges at Real-time Congestion Prices determined as specified herein, net of any payments specified herein for each of the Market Buyer's load buses.

(g) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the transmission congestion payments at each Generating Market Buyer's generation bus to be paid at Real-time Congestion Prices, determined by the product of the hourly Real-time Congestion Price at the relevant bus times the Generating Market Buyer's megawatts of generation at such generation bus in the hour in excess of the energy scheduled to be injected at that bus in that hour in the Day-ahead Energy Market. To the extent that the energy actually injected at the generation bus is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Generating Market Buyer shall be debited for the difference at the Real-time Congestion Price for the generation bus at the time of the shortfall. The megawatts of generation at each generation bus shall be the sum of the megawatts of generation for that bus of that Generating Market Buyer plus any megawatts of bilateral purchases of that Generating Market Buyer attributable to that bus. The total generation revenue for each Generating Market Buyer shall be the sum, for each of the Generating Market Buyer's generation buses, of the revenues at Day-ahead Congestion Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Congestion Prices determined as specified herein, net of any debits specified herein for each of the Market Buyer's generation buses.

(h) A Market Seller shall be paid for transmission congestion that results from the Real-time sales of energy to the extent of its hourly net deliveries to the PJM Region of energy in excess of amounts scheduled in the Day-ahead Energy Market from the Market Seller's resources. For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the hourly amounts delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region. The total real-time generation revenues for each Market Seller shall be the sum of its credits determined by the

product of (i) the hourly net amount of energy delivered to the PJM Region at the applicable generation or interface bus in excess of the amount scheduled to be delivered in that hour at that bus in the Day-ahead Energy Market from each of the Market Seller's resources, times (ii) the hourly Real-time Congestion Price at that bus. To the extent that the energy actually injected at a generation or interface bus in any hour is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Market Seller shall be debited for the difference at the Real-time Congestion Price for the applicable bus at the time of the shortfall times the amount of the shortfall. The total generation revenue for each Market Seller shall be the sum, for each of the Market Seller's generation buses or Interface Pricing Points, of the revenues at Day-ahead Congestion Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Congestion Prices determined as specified herein, net of any debits specified herein for each of the Market Seller's generation or interface buses.

5.1.4 Transmission Customer Calculation.

Each Transmission Customer using Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), each Network Customer, and each Transmission Customer using Non-Firm Point-to-Point Transmission Service (as defined in the PJM Tariff) that has elected to pay Transmission Congestion Charges, shall be charged for the increased cost of energy during constrained hours for the delivery of energy using such Transmission Service. Except as specified in this subsection, a Transmission Congestion Charge shall be assessed for transmission use scheduled in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region and the Day-ahead Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. Transmission Congestion Charges shall be assessed for real-time transmission use in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. A Transmission Customer shall be paid for Transmission Congestion Charges for real-time transmission use falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Congestion Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Congestion Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region.

5.1.4A Transaction Calculation

Each Market Participant entering into transactions in the PJM Interchange Energy Markets shall be charged for the increased cost of energy during constrained hours for the delivery of energy on the scheduled path. Except as specified in this subsection, a Transmission Congestion Charge shall be assessed for cleared MWh in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Congestion Price at the sink

point and the Day-ahead Congestion Price at the source point. Transmission Congestion Charges shall be assessed for real-time cleared MWh in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Congestion Price at the sink point and the Real-time Congestion Price at the source point. Such Market Participant shall be paid for Transmission Congestion Charges for real-time cleared MWh falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Congestion Price at the sink point and the Real-time Congestion Price at the source point.

5.1.5 Operating Margin Customer Calculation.

Each Control Area purchasing Operating Margin shall be assessed Transmission Congestion Charges for any increase in the cost of energy resulting from the provision of Operating Margin. The Transmission Congestion Charge shall be the amount of Operating Margin purchased in an hour multiplied by the difference in the Locational Marginal Price at what would be the delivery Interface Pricing Point and the Locational Marginal Price at what would be the source Interface Pricing Point, if the operating contingency that was the basis for the purchase of Operating Margin had occurred in that hour. Operating Margin may be allocated among multiple source and delivery Interface Pricing Points in accordance with an applicable load flow study.

5.1.6 Transmission Loading Relief Customer Calculation.

(a) Each Transmission Loading Relief Customer shall be assessed Transmission Congestion Charges for any increase in the cost of energy in the PJM Region resulting from its energy schedules over contract paths outside the PJM Region during Transmission Loading Relief.

(b) The Transmission Congestion Charge shall be the total amount of energy specified in such energy schedules multiplied by the difference between a Locational Marginal Price calculated by the Office of the Interconnection for the energy schedule source location specified in the NERC Interchange Distribution Calculator and a Locational Marginal Price calculated by the Office of the Interconnection for the energy schedule sink location specified in the NERC Interchange Distribution Calculator. Transmission Congestion Charges that are less than zero shall be set equal to zero for Transmission Loading Relief Customers.

(c) The Office of the Interconnection will determine the Locational Marginal Prices at the energy schedule source and sink locations external to PJM with reference to and based solely on the prices of energy in the PJM Region and at the Interface Pricing Points between adjacent Control Areas and the PJM Region and the system conditions and actual power flow distributions as described by the PJM State Estimator program. The Office of the Interconnection will determine the Locational Marginal Prices at the external energy schedule source and sink locations and the resulting Congestion Charge based on the portion of the energy schedule that flows through the PJM Region as reflected by the flow distributions from the PJM State Estimator program.

5.1.7 Total Transmission Congestion Charges.

The total Transmission Congestion Charges collected by PJMSettlement each hour will be the aggregate net amounts determined as specified in the PJM Manuals. PJMSettlement shall collect Transmission Congestion Charges for each hour the transmission system operates under constrained conditions.

5.4 Transmission Loss Charge Calculation.

5.4.1 Calculation by Office of the Interconnection.

The Office of the Interconnection shall calculate Transmission Loss Charges for each Network Service User, Market Participant in the PJM Interchange Energy Market, and each Transmission Customer.

5.4.2 General.

(a) The basis for the Transmission Loss Charges shall be the differences in the Locational Marginal Prices, defined as the Loss Price at a bus, between points of delivery and points of receipt, as determined in accordance with Section 2 of this Schedule.

(b) The Office of the Interconnection shall calculate Loss Prices in the form of Day-ahead Loss Prices and Real-time Loss Prices for the PJM Region, in accordance with Section 2 of this Schedule.

5.4.3 Network Service User Calculation.

(a) Each Network Service User shall be charged for the increased cost of transmission losses to deliver the output of its firm Capacity Resources or other owned or contracted for resources, its firm bilateral purchases, and its non-firm bilateral purchases.

(b) Market Buyers shall be charged for transmission losses resulting from all load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served from the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead Loss Price applicable to each relevant load bus.

(c) Generating Market Buyers shall be reimbursed for transmission losses resulting from all energy scheduled to be delivered to the PJM Interchange Energy Market in the Day-ahead Energy Market at the Day-ahead Loss Price applicable to each relevant generation bus.

(d) Market Sellers shall be reimbursed for transmission losses resulting from all energy scheduled to be delivered in the Day-ahead Energy Market at the Day-ahead Loss Prices applicable to each relevant generation bus.

(e) The hourly net amount of energy delivered at each generation bus is determined by revenue meter data, if available, or by the State Estimator, if revenue meter data is not available. The total load actually served at each load bus is initially determined by the State Estimator. For each Electric Distributor that reports hourly net energy flows from metered tie lines and for which all generators within the Electric Distributor's territory report revenue quality, hourly net energy delivered, the total revenue meter load within the Electric Distributor's territory is calculated as the sum of all net import energy flows reported by their tie revenue meters and all net generation reported via generator revenue meters. The amount of load at each of such Electric Distributor's load buses calculated by the State Estimator is then adjusted, in proportion

to its share of the total load of that Electric Distributor, in order that the total amount of load across all of the Electric Distributor's load buses matches its total revenue meter calculated load.

(f) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the Transmission Loss Charges at each Market Buyer's load bus to be charged for losses at Real-time Loss Prices determined by the product of the hourly Real-time Loss Prices at the relevant bus times the Market Buyer's megawatts of load (net of operating Behind The Meter Generation, but not to be less than zero) at the bus in that hour in excess of the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the hour in the Day-ahead Energy Market. To the extent that the load (net of operating Behind The Meter Generation, but not to be less than zero) actually served at a load bus is less than the load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) scheduled to be served at that bus in the Day-ahead Energy Market, the Market Buyer shall be paid for the difference at the Real-time Loss Price for the load bus at the time of the shortfall. The megawatts of load at each load bus shall be the sum of the megawatts of load (net of operating Behind The Meter Generation, but not less than zero) for that bus of that Market Buyer plus any megawatts of that Market Buyer's bilateral sales attributable to that bus. The total load charge for each Market Buyer shall be the sum, for each of a Market Buyer's load buses, of the charges at Day-ahead Loss Price determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1a plus the charges at Real-time Loss Prices determined as specified herein, net of any payments specified herein for each of the Market Buyer's load buses.

(g) At the end of each hour during an Operating Day, the Office of the Interconnection shall calculate the transmission loss payments at each Generating Market Buyer's generation bus to be paid at Real-time Loss Prices, determined by the product of the hourly Real-time Loss Price at the relevant bus times the Generating Market Buyer's megawatts of generation at such generation bus in the hour in excess of the energy scheduled to be injected at that bus in that hour in the Day-ahead Energy Market. To the extent that the energy actually injected at the generation bus is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Generating Market Buyer shall be debited for the difference at the Real-time Loss Price for the generation bus at the time of the shortfall. The megawatts of generation at each generation bus shall be the sum of the megawatts of generation for that bus of that Generating Market Buyer plus any megawatts of bilateral purchases of that Generating Market Buyer attributable to that bus. The total generation revenue for each Generating Market Buyer shall be the sum, for each of the Generating Market Buyer's generation buses, of the revenues at Day-ahead Loss Price determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Loss Prices determined as specified herein, net of any debits specified herein for each of the Market Buyer's generation buses.

(h) A Market Seller shall be paid for transmission losses that results from the Real-time sales of Spot Market Energy to the extent of its hourly net deliveries to the PJM Region of energy in excess of amounts scheduled in the Day-ahead Energy Market from the Market Seller's resources. For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the hourly amounts delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region. The

total real-time generation revenues for each Market Seller shall be the sum of its credits determined by the product of (i) the hourly net amount of energy delivered to the PJM Region at the applicable generation or interface bus in excess of the amount scheduled to be delivered in that hour at that bus in the Day-ahead Energy Market from each of the Market Seller's resources, times (ii) the hourly Real-time Loss Price at that bus. To the extent that the energy actually injected at a generation bus or Interface Pricing Point in any hour is less than the energy scheduled to be injected at that bus or point in the Day-ahead Energy Market, the Market Seller shall be debited for the difference at the Real-time Loss Price for the applicable bus or point at the time of the shortfall times the amount of the shortfall. The total generation revenue for each Market Seller shall be the sum, for each of the Market Seller's generation buses or Interface Pricing Points, of the revenues at Day-ahead Loss Prices determined in accordance with the Day-ahead Energy Market as specified in Section 1.10.1A plus the revenues at Real-time Loss Prices determined as specified herein, net of any debits specified herein for each of the Market Seller's generation buses or Interface Pricing Points.

5.4.4 Transmission Customer Calculation.

Each Transmission Customer using Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), each Network Customer, and each Transmission Customer using Non-Firm Point-to-Point Transmission Service (as defined in the PJM Tariff), shall be charged for the increased cost of transmission losses for the delivery of energy using such Transmission Service. Except as specified in this subsection, a Transmission Loss Charge shall be assessed for transmission use scheduled in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Loss Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region and the Day-ahead Loss Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. Transmission Loss Charges shall be assessed for real-time transmission use in excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Loss Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Loss Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region. A Transmission Customer shall be paid for Transmission Loss Charges for real-time transmission use falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Loss Price at the delivery point or the delivery Interface Pricing Point at the boundary of the PJM Region, and the Real-time Loss Price at the source point or the source Interface Pricing Point at the boundary of the PJM Region or the source Interface Pricing Point at the boundary of the PJM Region.

5.4.4A Transaction Calculation.

Each Market Participant entering into transactions in the PJM Interchange Energy Market shall be charged for the increased cost of transmission losses on the scheduled path. Except as specified in this subsection, a Transmission Loss Charge shall be assessed for cleared MWh in the Day-ahead Energy Market, calculated as the amount to be delivered multiplied by the difference between the Day-ahead Loss Price at the sink point and the Day-ahead Loss Price at the source point. Transmission Loss Charges shall be assessed for real-time cleared MWh in

excess of the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the excess amount multiplied by the difference between the Real-time Loss Price at the sink point and the Real-time Loss Price at the source point. Such Market Participant shall be paid for Transmission Loss Charges for real-time cleared MWh falling below the amounts scheduled for each hour in the Day-ahead Energy Market, calculated as the shortfall amount multiplied by the difference between the Real-time Loss Price at the sink point and the Real-time Loss Price at the source point.

5.4.5 Total Transmission Loss Charges.

The total Transmission Loss Charges collected by PJMSettlement each hour will be the aggregate net amounts determined as specified in this Schedule.

6.1 Introduction.

The following procedures shall apply to any generation resource subject to the dispatch of the Office of the Interconnection that, as a result of transmission constraints, the Office of the Interconnection determines, in the exercise of Good Utility Practice, must be run in order to maintain the reliability of service in the PJM Region. The provisions of this Schedule shall otherwise apply to the scheduling, dispatch, operation and accounting treatment of such resources, to the extent not inconsistent with the provisions of this Section 6.

1.5 Procedure for Development of the Regional Transmission Expansion Plan.

1.5.1 Commencement of the Process.

(a) The Office of the Interconnection shall initiate the enhancement and expansion study process if (i) required as a result of a need for transfer capability identified by the Office of the Interconnection in its evaluation of requests for interconnection with the transmission system or for firm transmission service with a term of one year or more; (ii) required to address a need identified by the Office of the Interconnection's in its on-going evaluation of the transmission system's economic and operational adequacy and performance; (iii) required as a result of the Office of the Interconnection's assessment of the transmission system's compliance with Reliability First Corporation or SERC reliability criteria, more stringent reliability criteria, if any; or PJM operating criteria; (iv) constraints or available transfer capability shortage, including, but not limited to, available transfer capability shortages that prevent the simultaneous feasibility of stage 1A Auction Revenue Rights allocated pursuant to Section 7.4.2(b) of Schedule 1 of this Agreement, that are identified by the Office of the Interconnection as a result of generation additions or retirements, evaluation of load forecasts, congestion events on or operational performance of the transmission system, or proposals for the addition of Transmission Facilities in the PJM region; or (v) expansion of the transmission system is proposed by one or more Transmission Owners, Interconnection Customer, Network Service User or Transmission Customer, or any party that funds Network Upgrades pursuant to Section 7.8 of Schedule 1 of this Agreement..

(b) The Office of the Interconnection shall notify the Transmission Expansion Advisory Committee of the commencement of an enhancement and expansion study. The Transmission Expansion Advisory Committee shall notify the Office of the Interconnection in writing of any additional transmission considerations to be included.

1.5.2 Development of Scope, Assumptions and Procedures.

Once the need for an enhancement and expansion study has been established, the Office of the Interconnection shall consult with the Transmission Expansion Advisory Committee and the Subregional RTEP Committee, as appropriate, to prepare the study's scope, assumptions and procedures.

1.5.3 Scope of Studies.

Enhancement and expansion studies shall be completed by the Office of the Interconnection in collaboration with the affected Transmission Owners, as required. In general, enhancement and expansion studies shall include:

(a) An identification of existing and projected limitations on the transmission system's physical, economic and/or operational capability or performance, with accompanying simulations to identify the costs of controlling those limitations. Potential enhancements and expansions will be proposed to mitigate limitations controlled by non-economic means.

(b) Evaluation and analysis of potential enhancements and expansions, including alternatives thereto, needed to mitigate such limitations.

(c) Identification, evaluation and analysis of potential expansions and enhancements including, demand response programs, and other alternative technologies as appropriate to maintain system reliability.

(d) Identification, evaluation and analysis of potential enhancements and expansions for the purposes of supporting competition in the PJM region.

(e) Identification, evaluation and analysis of upgrades to support Incremental Auction Revenue Rights requested pursuant to Section 7.8 of Schedule 1 of this Agreement.

(f) Identification, evaluation and analysis of upgrades to support all transmission customers, including native load and network service customers.

(g) Engineering studies needed to determine the effectiveness and compliance of recommended enhancements and expansions, with the following PJM criteria: system reliability, operational performance, and economic efficiency.

(h) Identification, evaluation and analysis of potential enhancements and expansions designed to ensure the Transmission System's capability can support the simultaneous feasibility of all stage 1A Auction Revenue Rights allocated pursuant to Section 7.4.2(b) of Schedule 1 of this Agreement. Enhancements and expansions related to stage 1A Auction Revenue Rights identified pursuant to this section shall be recommended for inclusion in the RTEP together with a recommended in-service date based on the results of the ten (10) year stage 1A simultaneous feasibility analysis. Any such recommended enhancement or expansion under this Section 1.5.3(f) shall include, but shall not be limited to, the reason for the upgrade, the cost of the upgrade, the cost allocation identified pursuant to Section 1.5.6(g) of Schedule 6 of this Agreement and an analysis of the benefits of the enhancement or expansion, provided that any such upgrades will not be subject to a market efficiency cost/benefit analysis.

1.5.4 Supply of Data.

(a) The Transmission Owners shall provide to the Office of the Interconnection on an annual or periodic basis as specified by the Office of the Interconnection, any information and data reasonably required by the Office of the Interconnection to perform the Regional Transmission Expansion Plan, including but not limited to the following: (i) a description of the total load to be served from each substation; (ii) the amount of any interruptible loads included in the total load (including conditions under which an interruption can be implemented and any limitations on the duration and frequency of interruptions); (iii) a description of all generation resources to be located in the geographic region encompassed by the Transmission Owner's transmission facilities, including unit sizes, VAR capability, operating restrictions, and any must-run unit designations required for system reliability or contract reasons; the (iv) current Local Plan; and (v) all criteria, assumptions and models used in the current Local Plan. The data required under

this Section shall be provided in the form and manner specified by the Office of the Interconnection.

(b) In addition to the foregoing, the Transmission Owners, those entities requesting transmission service and any other entities proposing to provide Transmission Facilities to be integrated into the PJM Region shall supply any other information and data reasonably required by the Office of the Interconnection to perform the enhancement and expansion study.

(c) The Office of the Interconnection also shall solicit from the Members, Transmission Customers and other interested parties, including but not limited to electric utility regulatory agencies within the States in the PJM Region and the State Consumer Advocates, information required by, or anticipated to be useful to, the Office of the Interconnection in its preparation of the enhancement and expansion study.

(d) The Transmission Expansion Advisory Committee and the Subregional RTEP Committee shall each facilitate a minimum of one initial assumptions meeting to be scheduled at the commencement of the RTEP process. The purpose of the assumptions meeting shall be the following: (i) establish the assumptions to be used in performing the evaluation and analysis of the potential enhancements and expansions to the Transmission Facilities, (ii) incorporate regulatory initiatives as appropriate, including state regulatory agency initiated programs, (iii) provide an open forum to review the impacts of regulatory actions, projected changes in load growth, demand response resources, generating capacity, market efficiency and other trends in the industry, and (iv) provide an open forum for the review of alternative scenarios proposed by the Committee participants. The final assumptions shall be determined by the Transmission Expansion Advisory Committee for both the Regional RTEP Project and Subregional RTEP Project.

(e) After the assumptions meeting(s) the Transmission Expansion Advisory Committee and the Subregional RTEP Committee shall facilitate additional meetings and shall post all communications required to provide early opportunity for the committee participants, (as defined in Sections 1.3(b) and 1.3(c) of this Schedule 6) to review and evaluate the following: any identified violations of reliability criteria; analyses of the economic performance of the transmission system; potential transmission solutions; and the proposed RTEP. These meetings will be scheduled as deemed necessary by the Office of the Interconnection or upon the request of the Transmission Expansion Advisory Committee or the Subregional RTEP Committees. The Office of the Interconnection will provide updates on the status of the development of the RTEP at these meetings or at the regularly scheduled meetings of the PJM Planning Committee.

(f) The Office of the Interconnection shall supply any information and data reasonably required by the Members, Transmission Customers and other impacted parties, including but not limited to, electric utility regulatory agencies within the States in the PJM Region, and the State Consumer Advocates, utilized to perform the Regional Transmission Expansion Plan. Such information and data shall be provided pursuant to the appropriate protection of confidentiality provisions.

(g) The Office of the Interconnection shall provide access throught the PJM website, to the Transmission Owner's Local Plan, including all criteria, assumptions and models used by the Transmission Owners in developing their respective Local Plan ("Local Plan Information"). Local Plan Information shall be provided consistent with: (1) any applicable confidentiality provisions set forth in Section 18.17 of this Operating Agreement; (2) PJM's CEII process; and (3) any applicable copyright limitations. Notwithstanding the foregoing, PJM may share with a third party Local Plan Information that has been designated as confidential, pursuant to the provisions for such designation as set forth in Section 18.17 of this Operating Agreement and subject to: (i) agreement by the disclosing Transmission Owner consistent with the process set forth in this Operating Agreement; and (ii) an appropriate non-disclosure agreement to be executed by PJM, the Transmission Owner and the requesting third party. With the exception of confidential, CEII and copyright protected information, Local Plan Information will be provided for full review by the Planning Committee, the TEAC and the Subregional RTEP Committees.

1.5.5 Coordination of the Regional Transmission Expansion Plan.

(a) The Regional Transmission Expansion Plan shall be developed in accordance with the principles of interregional coordination with the transmission systems of the surrounding regional reliability councils and with the local transmission providers, through the Transmission Expansion Advisory Committee and the Subregional RTEP Committee.

(b) The Regional Transmission Expansion Plan shall be developed taking into account the processes for coordinated regional transmission expansion planning established under the following agreements: Joint Operating Agreement Between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C.; Northeastern ISO/RTO Planning Coordination Protocol; Joint Reliability Coordination Agreement Between the Midwest independent System Operator, Inc.; PJM Interconnection, L.L.C. and Progress Energy Carolinas. Coordinated regional transmission expansion planning shall also incorporate input from parties that may be impacted by the coordination efforts, including but not limited to, the Members, Transmission Customers, electric utility regulatory agencies in the PJM Region, and the State Consumer Advocates, in accordance with the terms and conditions of the applicable regional coordination agreements.

(c) The Regional Transmission Expansion Plan shall be developed by the Office of the Interconnection in consultation with the Transmission Expansion Advisory Committee during the enhancement and expansion study process.

(d) The Regional Transmission Expansion Plan shall be developed taking into account the processes for coordination of the Regional and subregional systems.

1.5.6 Development of the Recommended Regional Transmission Expansion Plan.

(a) The Office of the Interconnection shall be responsible for the development of the Regional Transmission Expansion Plan and for conducting the studies on which the plan is based. The Regional Transmission Expansion Plan, including the Regional RTEP Projects, the Subregional RTEP Projects and the Supplemental Projects shall be developed through an open

and collaborative process with opportunity for meaningful participation through the Transmission Expansion Advisory Committee and the Subregional RTEP Committee.

(b) Upon completion of its studies and analysis, the Office of the Interconnection shall prepare a recommended enhancement and expansion plan, which shall include alternative projects or solutions as applicable, for review by the Transmission Expansion Advisory Committee. The Transmission Expansion Advisory Committee shall facilitate open meetings and communications as necessary to provide opportunity for the Transmission Expansion Advisory Committee participants to collaborate on the preparation of the recommended enhancement and expansion plan. The Office of the Interconnection also shall invite interested parties to submit comments on the plan to the Transmission Expansion Advisory Committee and to the Office of the Interconnection.

(c) The recommended plan shall separately identify enhancements and expansions for the three PJM subregions, the PJM Mid-Atlantic Region, the PJM West Region, and the PJM South Region, and shall incorporate recommendations from the Subregional RTEP Committee.

(c.01) The recommended plan shall separately identify enhancements and expansions that are classified as Supplemental Projects.

(d) The recommended plan shall identify enhancements and expansions that relieve transmission constraints and which, in the judgment of the Office of the Interconnection, are economically justified. Such economic expansions and enhancements shall be developed in accordance with the procedures, criteria and analyses described in Section 1.5.7 below.

(e) The recommended plan shall include proposed Merchant Transmission Facilities within the PJM Region and any other enhancement or expansion of the Transmission System requested by any participant which the Office of the Interconnection finds to be compatible with the Transmission System, though not required pursuant to Section 1.1, provided that (1) the requestor has complied, to the extent applicable, with the procedures and other requirements of Part IV of the PJM Tariff; (2) the proposed enhancement or expansion is consistent with applicable reliability standards, operating criteria and the purposes and objectives of the regional planning protocol; (3) the requestor shall be responsible for all costs of such enhancement or expansion (including, but not necessarily limited to, costs of siting, designing, financing, constructing, operating and maintaining the pertinent facilities), and (4) except as otherwise provided by Part IV of the PJM Tariff with respect to Merchant Network Upgrades, the requestor shall accept responsibility for ownership, construction, operation and maintenance of the enhancement or expansion through an undertaking satisfactory to the Office of the Interconnection.

(f) For each enhancement or expansion that is included in the recommended plan, the plan shall consider, based on the planning analysis: other input from participants, including any indications of a willingness to bear cost responsibility for such enhancement or expansion; and, when applicable, relevant projects being undertaken to ensure the simultaneous feasibility of Stage 1A ARRs, to facilitate Incremental ARRs pursuant to the provisions of Section 7.8 of Schedule 1 of this Agreement or to facilitate upgrades pursuant to Parts II, III or IV of the PJM

Tariff, and designate one or more Transmission Owners or other entities to construct, own and, unless otherwise provided, finance the recommended transmission enhancement or expansion. To the extent that one or more Transmission Owners are designated to construct, own and/or finance a recommended transmission enhancement or expansion, the recommended plan shall designate the Transmission Owner that owns transmission facilities located in the Zone where the particular enhancement or expansion is to be located. Otherwise, any designation under this paragraph of more than one entity to construct, own and/or finance a recommended transmission enhancement or expansion shall also include a designation of proportional responsibility among them. Nothing herein shall prevent any Transmission Owner or other entity designated to construct, own and/or finance a recommended transmission enhancement or expansion from agreeing to undertake its responsibilities under such designation jointly with other Transmission Owners or other entities.

(g) Based on the planning analysis and other input from participants, including any indications of a willingness to bear cost responsibility for an enhancement or expansion, the recommended plan shall, for any enhancement or expansion that is included in the plan, designate (1) the Market Participant(s) in one or more Zones, or any other party that has agreed to fully fund upgrades pursuant to this Agreement or the PJM Tariff, that will bear cost responsibility for such enhancement or expansion, as and to the extent provided by any provision of the PJM Tariff or this Agreement, (2) in the event and to the extent that no provision of the PJM Tariff or this Agreement assigns cost responsibility, the Market Participant(s) in one or more Zones from which the cost of such enhancement or expansion shall be recovered through charges established pursuant to Schedule 12 of the Tariff, and (3) in the event and to the extent that the Coordinated System Plan developed under the Joint Operating Agreement Between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C. assigns cost responsibility, the Market Participant(s) in one or more Zones from which the cost of such enhancement or expansion shall be recovered. Any designation under clause (2) of the preceding sentence (A) shall further be based on the Office of the Interconnection's assessment of the contributions to the need for, and benefits expected to be derived from, the pertinent enhancement or expansion by affected Market Participants and, (B), subject to FERC review and approval, shall be incorporated in any amendment to Schedule 12 of the PJM Tariff that establishes a Transmission Enhancement Charge Rate in connection with an economic expansion or enhancement developed under Sections 1.5.6(d) and 1.5.7 of this Schedule 6 , (C) the costs associated with expansions and enhancements required to ensure the simultaneous feasibility of stage 1A Auction Revenue Rights allocated pursuant to Section 7 of Schedule 1 of this Agreement shall (1) be allocated across transmission zones based on each zone's stage 1A eligible Auction Revenue Rights flow contribution to the total stage 1A eligible Auction Revenue Rights flow on the facility that limits stage 1A ARR feasibility and (2) within each transmission zone the Network Service Users and Transmission Customers that are eligible to receive stage 1A Auction Revenue Rights shall be the Responsible Customers under Section (b) of Schedule 12 of the PJM Tariff for all expansions and enhancements included in the Regional Transmission Expansion Plan to ensure the simultaneous feasibility of stage 1A Auction Revenue Rights, and (D) the costs associated with expansions and enhancements required to reduce to zero the Locational Price Adder for LDAs as described in Section 15 of Attachment DD of OATT shall (1) be allocated across transmission zones based on each zone's pro rata

share of load in such LDA and (2) within each transmission zone, to all LSEs serving load in such LDA pro rata based on such load.

Any designation under clause (3), above, (A) shall further be based on the Office of the Interconnection's assessment of the contributions to the need for, and benefits expected to be derived from, the pertinent enhancement or expansion by affected Market Participants, and (B), subject to FERC review and approval, shall be incorporated in an amendment to a Schedule of the PJM Tariff which establishes a charge in connection with the pertinent enhancement or expansion. Before designating fewer than all customers using Point-to-Point Transmission Service or Network Integration Transmission Service within a Zone as customers from which the costs of a particular enhancement or expansion may be recovered, Transmission Provider shall consult, in a manner and to the extent that it reasonably determines to be appropriate in each such instance, with affected state utility regulatory authorities and stakeholders. When the plan designates more than one responsible Market Participant, it shall also designate the proportional responsibility among them. Notwithstanding the foregoing, with respect to any facilities that the Regional Transmission Expansion Plan designates to be owned by an entity other than a Transmission Owner, the plan shall designate that entity as responsible for the costs of such facilities.

(g.01) Certain Regional RTEP Project(s) and Subregional RTEP Project(s) may not be required for compliance with the following PJM criteria: system reliability, operational performance, or economic efficiency, pursuant to a determination by the Office of the Interconnection. These Supplemental Projects shall be separately identified in the RTEP and are not subject to approval by the PJM Board.

(h) Any Transmission Owner and other participants on the Transmission Expansion Advisory Committee may offer an alternative.

(h.01) The Office of the Interconnection shall offer an alternative for review by the Transmission Expansion Advisory Committee or the Subregional RTEP Committee when the Office of the Interconnection determines, in its sole discretion that an alternative exists.

(i) If the Office of the Interconnection adopts the alternative, based upon its review of the relative costs and benefits, the ability of the alternative to supply the required level of transmission service, and its impact on the reliability of the Transmission Facilities, the Office of the Interconnection shall make any necessary changes to the recommended plan.

(j) If, based upon its review of the relative costs and benefits, the ability of the alternative to supply the required level of transmission service, and the alternative's impact on the reliability of the Transmission Facilities, the Office of the Interconnection does not adopt an alternative proposed by a Transmission Owner or Owners, the Transmission Owner or Owners whose alternative or alternatives have not been accepted or to whom cost responsibility has been assigned and other participants on the Transmission Expansion Advisory Committee may require that its or their alternative(s) be submitted to the Dispute Resolution Procedures in Schedule 5 of the Operating Agreement.

(k) Schedule 5 of the Operating Agreement, the Dispute Resolution Procedures may be requested by the parties to a dispute arising from the Regional Transmission Expansion Plan or its development.

1.5.7 Development of Economic Transmission Enhancements and Expansions.

(a) In June of each year, concurrent with the PJM Board's consideration and approval of the reliability-based transmission enhancement and expansions to be included in the Regional Transmission Expansion Plan, the Office of the Interconnection shall obtain PJM Board approval of the assumptions to be used in performing the market efficiency analysis described in this section to identify enhancements or expansions that could relieve transmission constraints that have an economic impact ("economic constraints"). Such assumptions shall include, but not be limited to, the discount rate used to determine the present value of the Total Annual Enhancement Benefit and Total Enhancement Cost, and the annual revenue requirement, including the recovery period, used to determine the Total Enhancement Cost. The discount rate shall be based on the Transmission Owners' most recent after-tax embedded cost of capital weighted by each Transmission Owner's total transmission capitalization. Each Transmission Owner shall provide the Office of the Interconnection with the Transmission Owner's most recent after-tax embedded cost of capital, total transmission capitalization, and levelized carrying charge rate, including the recovery period. The recovery period shall be consistent with recovery periods allowed by the Commission for comparable facilities. Prior to PJM Board consideration of such assumptions, the assumptions shall be presented to the Transmission Expansion Advisory Committee for review and comment.

(b) Following PJM Board approval of the assumptions, the Office of the Interconnection shall perform a market efficiency analysis to compare the costs and benefits of (i) accelerating reliability-based enhancements or expansions already included in the Regional Transmission Plan that if accelerated also could relieve one or more economic constraints; (ii) modifying reliability–based enhancements or expansions already included in the Regional Transmission Plan that as modified would relieve one or more economic constraints; and (iii) new enhancements or expansions that could relieve one or more economic constraints, but for which no reliability-based need has been identified. Economic constraints include, but are not limited to, constraints that cause (1) significant historical gross congestion; (2) significant historical unhedgeable congestion; (3) pro-ration of Stage 1B ARR requests as described in section 7.4.2(c) of Schedule 1 of this Agreement; or (4) significant simulated congestion as forecast in the market efficiency analysis.

(c) The process for conducting the market efficiency analysis described in subsection (b) above shall include the following:

(i) The Office of the Interconnection shall identify and provide to the Transmission Expansion Advisory Committee a list of economic constraints to be evaluated in the market efficiency analysis.

(ii) The Office of the Interconnection shall identify any planned reliability-based enhancements or expansions already included in the Regional Transmission Expansion Plan,

which if accelerated would relieve such constraints, and present any such proposed reliability-based enhancements and expansions to be accelerated to the Transmission Expansion Advisory Committee for review and comment. The PJM Board, upon consideration of the advice of the Transmission Expansion Advisory Committee, thereafter shall consider and vote to approve any accelerations.

(iii) The Office of the Interconnection shall evaluate whether including any additional economic-based enhancements or expansions in the Regional Transmission Expansion Plan or modifications of existing Regional Transmission Expansion Plan reliability-based enhancements or expansions would relieve an economic constraint. In addition, any market participant at any time may submit to the Office of the Interconnection a proposal to construct an additional economic-based enhancement or expansion to relieve an economic constraint. To be considered in the market efficiency analysis commencing after approval of the Regional Transmission Expansion Plan by the PJM Board in June, market participant proposals to construct an additional economic-based enhancement or expansion must be received by the Office of the Interconnection by December 31 of the same year. Upon completion of its evaluation, including consideration of any eligible market participant proposed economic-based enhancements or expansions, the Office of the Interconnection shall present to the Transmission Expansion Advisory Committee a description of recommended new economic-based enhancements and expansions for review and comment. Upon consideration of the advice of the Transmission Expansion Advisory Committee, the PJM Board shall consider any new economic-based enhancements and expansions for inclusion in the Regional Transmission Plan and for those enhancements and expansions it approves, the PJM Board shall designate (a) the entity or entities that will be responsible for constructing and owning or financing the additional economic-based enhancements and expansions, (b) the estimated costs of such enhancements and expansions, and (c) the market participants that will bear responsibility for the costs of the additional economic-based enhancements and expansions pursuant to section 1.5.6(g) of this Schedule 6. In the event the entity or entities designated as responsible for construction, owning or financing a designated new economic-based enhancement or expansion declines to construct, own or finance the new economic-based enhancement or expansion, the enhancement or expansion will not be included in the Regional Transmission Expansion Plan but will be included in the report filed with the FERC in accordance with sections 1.6 and 1.7 of this Schedule. This report also shall include information regarding PJM Board approved accelerations of reliability-based enhancements or expansions that an entity declines to accelerate.

(d) To determine the economic benefits of accelerating or modifying planned reliability-based enhancements or expansions or of constructing additional economic based enhancements or expansions and whether such economic-based enhancements or expansion are eligible for inclusion in the Regional Transmission Expansion Plan, the Office of the Interconnection shall perform and compare market simulations with and without the proposed accelerated or modified planned reliability-based enhancements or expansions or the additional economic-based enhancements or expansions as applicable, using the Benefit/Cost Ratio calculation set forth below in this section 1.5.7(d). An economic-based enhancement or expansion shall be included in the Regional Transmission Expansion Plan recommended to the PJM Board, if the relative benefits and costs of the economic-based enhancement or expansion meet a Benefit/Cost Ratio Threshold of at least 1.25:1.

The Benefit/Cost Ratio shall be determined as follows:

Benefit/Cost Ratio = [Present value of the Total Annual Enhancement Benefit for each of the first 15 years of the life of the enhancement or expansion] ÷ [Present value of the Total Enhancement Cost for each of the first 15 years of the life of the enhancement or expansion]

Where

Total Annual Enhancement Benefit = Energy Market Benefit + Reliability Pricing Model Benefit

and

Energy Market Benefit = [.70] * [Change in Total Energy Production Cost] + [.30] * [Change in Load Energy Payment]

and

Change in Total Energy Production Cost = [the estimated total annual fuel costs, variable O&M costs, and emissions costs of the dispatched resources in the PJM Region without the economic-based enhancement or expansion] – [the estimated total annual fuel costs, variable O&M costs, and emissions costs of the dispatched resources in the PJM Region with the economic-based enhancement or expansion]

and

Change in Load Energy Payment = [the annual sum of (the hourly estimated zonal load megawatts for each Zone) * (the hourly estimated zonal Locational Marginal Price for each Zone without the economic-based enhancement or expansion)] – [the annual sum of (the hourly estimated zonal load megawatts for each Zone) * (the hourly estimated zonal Locational Marginal Price for each Zone with the economic-based enhancement or expansion)] – [the change in value of transmission rights for each Zone with the economic-based enhancement or expansion (as measured using currently allocated Auction Revenue Rights plus additional Auction Revenue Rights made available by the proposed acceleration or modification of the planned reliability-based enhancement or expansion or new economic based enhancement or expansion)]. For economic-based enhancements and expansions for which cost responsibility is assigned pursuant to section (b)(i) of Schedule 12 of the PJM Tariff, the Change in the Load Energy

Payment shall be the sum of the Change in Load Energy Payment in all Zones. For economic-based enhancements or expansions for which cost responsibility is assigned pursuant to section (b)(v) of Schedule 12 of the PJM Tariff, the Change in Load Energy Payment shall be the sum of the Change in the Load Energy Payment only of the Zones that show a decrease in Load Energy Payment.

and

Reliability Pricing Benefit = [.70] * [Change in Total System Capacity Cost] + [.30] * [Change in Load Capacity Payment]

and

Change in Total System Capacity Cost = [the sum of (the megawatts that are estimated to be cleared in the Base Residual Auction under Attachment DD of the PJM Tariff) * (the prices that are estimated to be contained in the Sell Offers for each such cleared megawatt without the economic-based enhancement or expansion) * (the number of days in the study year)] – [the sum of (the megawatts that are estimated to be cleared in the Base Residual Auction under Attachment DD of the PJM Tariff) * (the prices that are estimated to be contained in the Sell Offers for each such cleared megawatt with the economic-based enhancement or expansion) * (the number of days in the study year)]

and

Change in Load Capacity Payment = [the sum of (the estimated zonal load megawatts in each Zone) * (the estimated Final Zonal Capacity Prices under Attachment DD of the PJM Tariff without the economic-based enhancement or expansion) * (the number of days in the study year)] – [the sum of (the estimated zonal load megawatts in each Zone) * (the estimated Final Zonal Capacity Prices under Attachment DD of the PJM Tariff with the economic-based enhancement or expansion) * (the number of days in the study year)]. The Change in Load Capacity Payment shall take account of the change in value of Capacity Transfer Rights in each Zone, including any additional Capacity Transfer Rights made available by the proposed acceleration or modification of the planned reliability-based enhancement or expansion or new economic based enhancement or expansion. For economic-based enhancements and expansions for which cost responsibility is assigned pursuant to section (b)(i) of Schedule 12 of the PJM Tariff, the Change in the Load Capacity Payment shall be the sum

of the change in Load Capacity Payment in all Zones. For economic-based enhancements or expansions for which cost responsibility is assigned pursuant to section (b)(v) of Schedule 12 of the PJM Tariff, the Change in Load Capacity Payment shall be the sum of the change in the Load Capacity Payment only of the Zones that show a decrease in Load Capacity Payment.

and

Total Enhancement Cost (except for accelerations of planned reliability-based enhancements or expansions) = the estimated annual revenue requirement for the economic-based enhancement or expansion.

Total Enhancement Cost (for accelerations of planned reliability-based enhancements or expansions) = the estimated change in annual revenue requirement resulting from the acceleration of the planned reliability-based enhancement or expansion, taking account of all of the costs incurred that would not have been incurred but for the acceleration of the planned reliability-based enhancement or expansion.

(e) For informational purposes only, to assist the Office of the Interconnection and the Transmission Expansion Advisory Committee in evaluating the economic benefits of accelerating planned reliability-based enhancements or expansions or of constructing a new economic-based enhancement or expansion, the Office of the Interconnection shall calculate and post on the PJM internet site the change in the following metrics on a zonal and system-wide basis: (i) total energy production costs (fuel costs, variable O&M costs and emissions costs);(ii) total load energy payments (zonal load MW times zonal load Locational Marginal Price); (iii) total generator revenue from energy production (generator MW times generator Locational Marginal Price); (iv) Financial Transmission Right credits (as measured using currently allocated Auction Revenue Rights plus additional Auction Revenue Rights made available by the proposed acceleration or modification of a planned reliability-based enhancement or expansion or new economic based enhancement or expansion); (v) marginal loss surplus credit; and (vi) total capacity costs and load capacity payments under the Office of the Interconnection's Commission-approved capacity construct.

(f) To assure that new economic-based enhancements and expansions included in the Regional Transmission Expansion Plan continue to be cost beneficial, the Office of the Interconnection annually shall review the costs and benefits of constructing such enhancements and expansions. In the event that there are changes in these costs and benefits, the Office of the Interconnection shall review the changes in costs and benefits with the Transmission Expansion Advisory Committee and recommend to the PJM Board whether the new economic-based enhancements and expansions continue to provide measurable benefits, as determined in accordance with subsection (d), and should remain in the Regional Transmission Expansion Plan. The annual review of the costs and benefits of constructing new economic-based enhancements and expansions included in the Regional Transmission Expansion Plan shall include review of changes in cost estimates of the economic-based enhancement or expansion,

and changes in system conditions, including but not limited to, changes in load forecasts, and anticipated Merchant Transmission Facilities, generation, and demand response, consistent with the requirements of subsection (k).

(g) With respect to each new economic-based enhancement or expansion included in the Regional Transmission Expansion Plan, the Office of the Interconnection shall provide to the Transmission Expansion Advisory Committee the level and type of new generation and demand response that could eliminate the need for the enhancement or expansion.

(h) For new economic enhancements or expansions with costs in excess of $50 million, an independent review of such costs shall be performed to assure both consistency of estimating practices and that the scope of the new economic-based enhancements and expansions is consistent with the new economic-based enhancements and expansions as recommended in the market efficiency analysis.

(i) For informational purposes only, the Office of the Interconnection shall post monthly on the PJM Internet site analyses of gross and unhedgeable congestion associated with transmission constraints in the PJM Region, including the level of available economic generation used to calculate unhedgeable congestion costs.

(j) At any time, market participants may submit to the Office of the Interconnection requests to interconnect Merchant Transmission Facilities or generation facilities pursuant to Part IV of the PJM Tariff that could address an economic constraint. In the event the Office of the Interconnection determines that the interconnection of such facilities would relieve an economic constraint, the Office of the Interconnection may designate the project as a "market solution" and, in the event of such designation, sections 36A or 41A of the PJM Tariff, as applicable, shall apply to the project.

(k) The assumptions used in the market efficiency analysis described in subsection (b) and any review of costs and benefits pursuant to subsection (f) shall include, but not be limited to, the following:

(i) Timely installation of Qualifying Transmission Upgrades, as defined in section 2.5.7 of Attachment DD of the PJM Tariff, that are committed to the PJM Region as a result of any Reliability Pricing Model Auction pursuant to Attachment DD of the PJM Tariff or any FRR Capacity Plan pursuant to Schedule 8.1 of the Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region, on file with FERC as PJM Interconnection, L.L.C. Rate Schedule FERC No. 44 ("RAA").

(ii) Availability of Generation Capacity Resources, as defined by section 1.33 of the RAA, that are committed to the PJM Region as a result of any Reliability Pricing Model Auction pursuant to Attachment DD of the PJM Tariff or any FRR Capacity Plan pursuant to Schedule 8.1 of the RAA.

(iii) Availability of Demand Resources as defined in section 1.13 of the RAA that are committed to the PJM Region as a result of any Reliability Pricing Model Auction pursuant to Attachment DD of the PJM Tariff or any FRR Capacity Plan pursuant to Schedule 8.1 of the RAA.

(iv) Availability of ILR Resources certified pursuant to section 5.13 of Attachment DD of the PJM Tariff.

(v) Addition of Customer Facilities pursuant to an executed Interconnection Service Agreement or Interim Interconnection Service Agreement.

(vi) Addition of Customer-Funded Upgrades pursuant to an executed Interconnection Construction Service Agreement or an Upgrade Construction Service Agreement.

(vii) Expected level of demand response over at least the ensuing fifteen years based on analyses that consider historic levels of demand response, expected demand response growth trends, impact of capacity prices, current and emerging technologies.

(viii) Expected levels of potential new generation and generation retirements over at least the ensuing fifteen years based on analyses that consider generation trends based on existing generation on the system, generation in the PJM interconnection queues and Capacity Resource Clearing Prices under Attachment DD of the PJM Tariff. If the Office of the Interconnection finds that the PJM reserve requirement is not met in any of its future year market efficiency analyses then it will model adequate future generation based on type and location of generation in existing PJM interconnection queues.

(ix) Items (i) through (vi) will be included in the market efficiency assumptions if qualified before January 1 of the year that the assumptions are presented to the PJM Board for approval in June. In the event that any of the items listed in (i) through (vi) above qualify for inclusion in the market efficiency analysis assumptions, however, because of the timing of the qualification the item was not included in the assumptions used in developing the most recent Regional Transmission Expansion Plan, the Office of the Interconnection, to the extent necessary, shall notify any entity constructing an economic-based enhancement or expansion that may be affected by inclusion of such item in the assumptions for the next market efficiency analysis described in subsection (b) and

any review of costs and benefits pursuant to subsection (f) that the need for the economic-based enhancement or expansion may be diminished or obviated as a result of the inclusion of the qualified item in the assumptions for the next annual market efficiency analysis or review of costs and benefits.

(l) For informational purposes only, with regard to economic-based enhancements or expansions that are included in the Regional Transmission Expansion Plan pursuant to subsection (d) of this section 1.5.7, the Office of the Interconnection shall perform sensitivity analyses around key inputs, such as price forecasts and expected levels of demand response, used in the market simulations to determine the Benefit/Cost Ratio for such enhancements and expansions and shall provide the results of such sensitivity analyses to the Transmission Expansion Advisory Committee.

2. NEW PARTIES

With regard to the addition, withdrawal or removal of a party to the Reliability Assurance Agreement, the Office of the Interconnection shall:

(a) Receive and evaluate the information submitted by entities that plan to serve loads within the PJM Region, including entities whose participation in the Agreement will expand the boundaries of the PJM Region. Such evaluation shall be conducted in accordance with the requirements of the Reliability Assurance Agreement; and

(b) Evaluate the effects of the withdrawal or removal of a party from the Reliability Assurance Agreement.

3. IMPLEMENTATION OF RELIABILITY ASSURANCE AGREEMENT

With regard to the implementation of the provisions of the Reliability Assurance Agreement, the Office of the Interconnection shall:

(a) Receive all required data and forecasts from the parties to the Reliability Assurance Agreement and other owners or providers of Capacity Resources;

(b) Perform all calculations and analyses necessary to determine the Forecast Pool Requirement and the capacity obligations imposed under the Reliability Assurance Agreement, including periodic reviews of the capacity benefit margin for consistency with the Reliability Principles and Standards, as the foregoing terms are defined in the Reliability Assurance Agreement;

(c) Monitor the compliance of each party to the Reliability Assurance Agreement with its obligations under the Reliability Assurance Agreement;

(d) Keep cost records, and bill and collect any costs or charges due from the parties to the Reliability Assurance Agreement and distribute those charges in accordance with the terms of the Reliability Assurance Agreement;

(e) Assist with the development of rules and procedures for determining and demonstrating the capability of Capacity Resources;

(f) Establish the capability and deliverability of Generation Capacity Resources consistent with the requirements of the Reliability Assurance Agreement;

(g) Establish standards and procedures for Planned Demand Resources;

(h) Collect and maintain generator availability data;

(i) Perform any other forecasts, studies or analyses required to administer the Reliability Assurance Agreement;

(j) Coordinate maintenance schedules for generation resources operated as part of the PJM Region;

(k) Determine and declare that an Emergency exists or has ceased to exist in all or any part of the PJM Region or announce that an Emergency exists or ceases to exist in a Control Area interconnected with the PJM Region;

(l) Enter into agreements for (i) the transfer of energy in Emergencies in the PJM Region or in a Control Area interconnected with the PJM Region and (ii) mutual support in such Emergencies with other Control Areas interconnected with the PJM Region; and

(m) Coordinate the curtailment or shedding of load, or other measures appropriate to alleviate an Emergency, to preserve reliability in accordance with FERC, NERC or Applicable Regional

Reliability Council principles, guidelines, standards and requirements and the PJM Manuals, and to ensure the operation of the PJM Region in accordance with Good Utility Practice.

PJM Reliability Assurance Agreement
(Clean Sections)

ARTICLE 1 -- DEFINITIONS

Unless the context otherwise specifies or requires, capitalized terms used herein shall have the respective meanings assigned herein or in the Schedules hereto for all purposes of this Agreement (such definitions to be equally applicable to both the singular and the plural forms of the terms defined). Unless otherwise specified, all references herein to Articles, Sections or Schedules, are to Articles, Sections or Schedules of this Agreement. As used in this Agreement:

1.1 Agreement

Agreement shall mean this Reliability Assurance Agreement, together with all Schedules hereto, as amended from time to time.

1.1A Annual Demand Resource

Annual Demand Resource shall mean a resource that is placed under the direction of the Office of the Interconnection during the Delivery Year, and will be available for an unlimited number of interruptions during such Delivery Year by the Office of the Interconnection, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time for the months of June through October and the following May, and 6:00AM through 9:00PM Eastern Prevailing Time for the months of November through April unless there is an Office of the Interconnection approved maintenance outage during October through April. The Annual Demand Resource must be available in the corresponding Delivery year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Annual Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

1 .2 Applicable Regional Reliability Council

Applicable Regional Reliability Council shall have the same meaning as in the PJM Tariff.

1.3 Base Residual Auction

Base Residual Auction shall have the same meaning as in Attachment DD to the PJM Tariff.

1.4 Behind The Meter Generation

Behind The Meter Generation shall mean 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 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 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.

1.5 Black Start Capability

Black Start Capability shall mean the ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the power system.

1.6 Capacity Emergency Transfer Objective ("CETO")

Capacity Emergency Transfer Objective ("CETO") shall mean the amount of electric energy that a given area must be able to import in order to remain within a loss of load expectation of one event in 25 years when the area is experiencing a localized capacity emergency, as determined in accordance with the PJM Manuals. Without limiting the foregoing, CETO shall be calculated based in part on EFORD determined in accordance with Paragraph C of Schedule 5.

1.7 Capacity Emergency Transmission Limit ("CETL")

Capacity Emergency Transmission Limit ("CETL") shall mean the capability of the transmission system to support deliveries of electric energy to a given area experiencing a localized capacity emergency as determined in accordance with the PJM Manuals.

1.8 Capacity Resources

Capacity Resources shall mean megawatts of (i) net capacity from existing or Planned Generation Capacity Resources meeting the requirements of Schedules 9 and 10 that are or will be owned by or contracted to a Party and that are or will be committed to satisfy that Party's obligations under this Agreement, or to satisfy the reliability requirements of the PJM Region, for a Delivery Year; (ii) net capacity from existing or Planned Generation Capacity Resources within the PJM Region not owned or contracted for by a Party which are accredited to the PJM Region pursuant to the procedures set forth in Schedules 9 and 10; and (iii) load reduction capability provided by Demand Resources, Energy Efficiency Resources, or ILR that are accredited to the PJM Region pursuant to the procedures set forth in Schedule 6.

1.9 Capacity Transfer Right

Capacity Transfer Right shall have the meaning specified in Attachment DD to the PJM Tariff.

1.10 Control Area

Control Area shall mean an electric power system or combination of electric power systems bounded by interconnection metering and telemetry to which a common generation control scheme is applied in order to:

(a) match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of NERC and Applicable Regional Reliability Councils;

(d) maintain power flows on transmission facilities within appropriate limits to preserve reliability; and

(e) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.11 Daily Unforced Capacity Obligation

Daily Unforced Capacity Obligation shall have the meaning set forth in Schedule 8 or, as to an FRR Entity, in Schedule 8.1.

1.12 Delivery Year

Delivery Year shall mean a Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Attachment DD to the Tariff or pursuant to an FRR Capacity Plan.

1.13 Demand Resource

Demand Resource or "DR" shall mean a Limited Demand Resource, Extended Summer Demand Resource, or Annual Demand Resource with a demonstrated capability to provide a reduction in demand or otherwise control load in accordance with the requirements of Schedule 6 that offers and that clears load reduction capability in a Base Residual Auction or Incremental Auction or that is committed through an FRR Capacity Plan. As set forth in Schedule 6, a Limited Demand Resource, Extended Summer Demand Resource or Annual Demand Resource may be an existing demand response resource or a Planned Demand Resource.

1.14 Demand Resource Provider

Demand Resource Provider shall have the meaning specified in Attachment DD to the PJM Tariff.

1.15 DR Factor

DR Factor shall mean that factor approved from time to time by the PJM Board used to determine the unforced capacity value of a Demand Resource or ILR in accordance with Schedule 6.

1.16 East RAA

East RAA shall mean that certain Reliability Assurance Agreement among Load-Serving Entities in the PJM Region, PJM Rate Schedule FERC No. 27.

1.17 Electric Cooperative

Electric Cooperative shall mean an entity owned in cooperative form by its customers that is engaged in the generation, transmission, and/or distribution of electric energy.

1.18 Electric Distributor

Electric Distributor shall mean an entity that owns or leases with rights equivalent to ownership electric distribution facilities that are providing electric distribution service to electric load within the PJM Region.

1.19 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.

1.20 End-Use Customer

End-Use Customer shall mean a Member that is a retail end-user of electricity within the PJM Region.

1.20A Energy Efficiency Resource

Energy Efficiency Resource shall mean a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, meeting the requirements of Schedule 6 of this Agreement and exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak periods as described in Schedule 6 and the PJM Manuals) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

1.20B Existing Generation Capacity Resource

Existing Generation Capacity Resource shall mean, for purposes of the must-offer requirement and mitigation of offers for any RPM Auction for a Delivery Year, a Generation Capacity Resource that, as of the date on which bidding commences for such auction: (a) is in service; or (b) is not yet in service, but has cleared any RPM Auction for any prior Delivery Year. Notwithstanding the foregoing, a Generation Capacity Resource for which construction has not commenced and which would otherwise have been treated as a Planned Generation Capacity Resource but for the fact that it was bid into RPM Auctions for at least two consecutive Delivery Years, and cleared the last such auction only because it was considered existing and its mitigated offer cap was accepted when its price offer would not have otherwise been accepted, shall be deemed to be a Planned Generation Capacity Resource. A Generation Capacity Resource shall be deemed to be in service if interconnection service has ever commenced (for resources located in the PJM Region), or if it is physically and electrically interconnected to an external Control Area and is in full commercial operation (for resources not located in the PJM Region). The additional megawatts of a Generation Capacity Resource that is being, or has been, modified to increase the number of megawatts of available installed capacity thereof shall not be deemed to be an Existing Generation Capacity Resource until such time as those megawatts (a) are in service; or (b) are not yet in service, but have cleared any RPM Auction for any prior Delivery Year.

1.20C Extended Summer Demand Resource

Extended Summer Demand Resource shall mean a resource that is placed under the direction of the Office of the Interconnection and that will be available June through October and the following May, and will be available for an unlimited number of interruptions during such months by the Office of the Interconnection, and will be capable of maintaining each such interruption for at least a 10-hour duration between the hours of 10:00AM to 10:00PM Eastern Prevailing Time. The Extended Summer Demand Resource must be available June through October and the following May in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as an Extended Summer Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

1.21 Facilities Study Agreement

Facilities Study Agreement shall have the same meaning as in the PJM Tariff

1.22 FERC

FERC shall mean the Federal Energy Regulatory Commission or any successor federal agency, commission or department.

1.23 Firm Point-To-Point Transmission Service

Firm Point-To-Point Transmission Service shall mean Firm Transmission Service provided pursuant to the rates, terms and conditions set forth in Part II of the PJM Tariff.

1.24 Firm Transmission Service

Firm Transmission Service shall mean transmission service that is intended to be available at all times to the maximum extent practicable, subject to an Emergency, an unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility or the Office of the Interconnection.

1.25 Fixed Resource Requirement Alternative or FRR Alternative

Fixed Resource Requirement Alternative or FRR Alternative shall mean an alternative method for a Party to satisfy its obligation to provide Unforced Capacity hereunder, as set forth in Schedule 8.1 to this Agreement.

1.26 Forecast Pool Requirement

Forecast Pool Requirement shall mean the amount equal to one plus the unforced reserve margin (stated as a decimal number) for the PJM Region required pursuant to this Agreement, as approved by the PJM Board pursuant to Schedule 4.1.

1.27 Forecast RTO ILR Obligation

Forecast RTO ILR Obligation shall have the same meaning as in the PJM Tariff.

1.28 Forecast Zonal ILR Obligation

Forecast Zonal ILR Obligation shall have the same meaning as in the PJM Tariff.

1.29 FRR Capacity Plan

FRR Capacity Plan shall mean a long-term plan for the commitment of Capacity Resources to satisfy the capacity obligations of a Party that has elected the FRR Alternative, as more fully set forth in Schedule 8.1 to this Agreement.

1.30 FRR Entity

FRR Entity shall mean, for the duration of such election, a Party that has elected the FRR Alternative hereunder.

1.31 FRR Service Area

FRR Service Area shall mean (a) the service territory of an IOU as recognized by state law, rule or order; (b) the service area of a Public Power Entity or Electric Cooperative as recognized by franchise or other state law, rule, or order; or (c) a separately identifiable geographic area that is: (i) bounded by wholesale metering, or similar appropriate multi-site aggregate metering, that is visible to, and regularly reported to, the Office of the Interconnection, or that is visible to, and regularly reported to an Electric Distributor and such Electric Distributor agrees to aggregate the load data from such meters for such FRR Service Area and regularly report such aggregated information, by FRR Service Area, to the Office of the Interconnection; and (ii) for which the FRR Entity has or assumes the obligation to provide capacity for all load

(including load growth) within such area . In the event that the service obligations of an Electric Cooperative or Public Power Entity are not defined by geographic boundaries but by physical connections to a defined set of customers, the FRR Service Area in such circumstances shall be defined as all customers physically connected to transmission or distribution facilities of such Electric Cooperative or Public Power Entity within an area bounded by appropriate wholesale aggregate metering as described above.

1.32 Full Requirements Service

Full Requirements Service shall mean wholesale service to supply all of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

1.33 Generation Capacity Resource

Generation Capacity Resource shall mean a generation unit, or the right to capacity from a specified generation unit, that meets the requirements of Schedules 9 and 10 of this Agreement. A Generation Capacity Resource may be an Existing Generation Capacity Resource or a Planned Generation Capacity Resource.

1.34 Generation Owner

Generation Owner shall mean a Member that owns or leases with rights equivalent to ownership facilities for the generation of electric energy that are located within the PJM Region. Purchasing all or a portion of the output of a generation facility shall not be sufficient to qualify a Member as a Generation Owner.

1.35 Generator Forced Outage

Generator Forced Outage shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the PJM Manuals. A reduction in output or removal from service of a generating unit in response to changes in market conditions shall not constitute a Generator Forced Outage.

1.36 Generator Maintenance Outage

Generator Maintenance Outage shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform repairs on specific components of the facility, if removal of the facility qualifies as a maintenance outage pursuant to the PJM Manuals.

1.37 Generator Planned Outage

Generator Planned Outage shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the Office of the Interconnection in accordance with the PJM Manuals.

1.38 Good Utility Practice

Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the region.

1.39 ILR Provider

ILR Provider shall have the meaning specified in Attachment DD to the PJM Tariff.

1.40 Incremental Auction

Incremental Auction shall mean the First Incremental Auction, the Second Incremental Auction, the Third Incremental Auction, or the Conditional Incremental Auction, each as defined in Attachment DD to the PJM Tariff.

1.41 Interconnection Agreement

Interconnection Agreement shall have the same meaning as in the PJM Tariff.

1.42 Interruptible Load for Reliability, or ILR

Interruptible Load for Reliability, or ILR, shall mean a resource with a demonstrated capability to provide a reduction in demand or otherwise control load in accordance with the requirements of Schedule 6 that is certified by PJM no later than three months prior to a Delivery Year. At a minimum, ILR shall be available for interruption for at least 10 times during the summer period of June through September in the Delivery Year, and will be capable of maintaining each such interruption for at least a 6-hour duration. At a minimum, the ILR shall be available for such interruptions on weekdays, other than NERC holidays, from 12:00PM (noon) to 8:00PM Eastern Prevailing Time in the corresponding Delivery Year.

1.43 IOU

IOU shall mean an investor-owned utility with substantial business interest in owning and/or operating electric facilities in any two or more of the following three asset categories: generation, transmission, distribution.

1.43A Limited Demand Resource

Limited Demand Resource shall mean a resource that is placed under the direction of the Office of the Interconnection and that will, at a minimum, be available for interruption for at

least 10 times during the summer period of June through September in the Delivery Year, and will be capable of maintaining each such interruption for at least a 6-hour duration. At a minimum, the Limited Demand Resource shall be available for such interruptions on weekdays, other than NERC holidays, from 12:00PM (noon) to 8:00PM Eastern Prevailing Time. The Limited Demand Resource must be available during the summer period of June through September in the corresponding Delivery Year to be offered for sale or Self-Supplied in an RPM Auction, or included as a Limited Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

1.44 Load Serving Entity or LSE

Load Serving Entity or LSE shall mean any entity (or the duly designated agent of such an entity), including a load aggregator or power marketer, (i) serving end-users within the PJM Region, and (ii) that has been granted the authority or has an obligation pursuant to state or local law, regulation or franchise to sell electric energy to end-users located within the PJM Region. Load Serving Entity shall include any end-use customer that qualifies under state rules or a utility retail tariff to manage directly its own supply of electric power and energy and use of transmission and ancillary services.

1.45 Locational Reliability Charge

Locational Reliability Charge shall mean the charge determined pursuant to Schedule 8.

1.46 Markets and Reliability Committee

Markets and Reliability Committee shall mean the committee established pursuant to the Operating Agreement as a Standing Committee of the Members Committee.

1.47 Member

Member shall mean an entity that satisfies the requirements of Sections 1.24 and 11.6 of the PJM Operating Agreement. In accordance with Article 4 of this Agreement, each Party to this Agreement also is a Member.

1.48 Members Committee

Members Committee shall mean the committee specified in Section 8 of the PJM Operating Agreement composed of the representatives of all the Members.

1.49 NERC

NERC shall mean the North American Electric Reliability Council or any successor thereto.

1.50 Network Resources

Network Resources shall have the meaning set forth in the PJM Tariff.

1.51 Network Transmission Service

Network Transmission Service shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part III of the PJM Tariff or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner (as that term is defined in the PJM Tariff).

1.52 Nominated Demand Resource Value

Nominated Demand Resource Value shall have the meaning specified in Attachment DD to the PJM Tariff.

1.53 Nominated ILR Value

Nominated ILR Value shall have the meaning specified in Attachment DD to the PJM Tariff.

1.54 Non-Retail Behind the Meter Generation

Non-Retail Behind the Meter Generation shall mean Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, and electric distribution companies to serve load.

1.55 Obligation Peak Load

Obligation Peak Load shall have the meaning specified in Schedule 8 of this Agreement.

1.56 Office of the Interconnection

Office of the Interconnection shall mean the employees and agents of PJM Interconnection, L.L.C., subject to the supervision and oversight of the PJM Board, acting pursuant to the Operating Agreement.

1.57 Operating Agreement of PJM Interconnection, L.L.C. or Operating Agreement

Operating Agreement of PJM Interconnection, L.L.C. or Operating Agreement shall mean that certain agreement, dated April 1, 1997 and as amended and restated June 2, 1997 and as amended from time to time thereafter, among the members of the PJM Interconnection, L.L.C.

1.58 Operating Reserve

Operating Reserve shall mean the amount of generating capacity scheduled to be available for a specified period of an operating day to ensure the reliable operation of the PJM Region, as specified in the PJM Manuals.

1.59 Other Supplier

Other Supplier shall mean a Member that is (i) a seller, buyer or transmitter of electric capacity or energy in, from or through the PJM Region, and (ii) is not a Generation Owner, Electric Distributor, Transmission Owner or End-Use Customer.

1.60 Partial Requirements Service

Partial Requirements Service shall mean wholesale service to supply a specified portion, but not all, of the power needs of a Load Serving Entity to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

1.61 Percentage Internal Resources Required

Percentage Internal Resources Required shall mean, for purposes of an FRR Capacity Plan, the percentage of the LDA Reliability Requirement for an LDA that must be satisfied with Capacity Resources located in such LDA.

1.62 Party

Party shall mean an entity bound by the terms of this Agreement.

1.63 PJM

PJM shall mean the PJM Board and the Office of the Interconnection.

1.64 PJM Board

PJM Board shall mean the Board of Managers of the PJM Interconnection, L.L.C., acting pursuant to the Operating Agreement.

1.65 PJM Manuals

PJM Manuals shall mean the instructions, rules, procedures and guidelines established by the Office of the Interconnection for the operation, planning and accounting requirements of the PJM Region.

1.66 PJM Open Access Transmission Tariff or PJM Tariff

PJM Open Access Transmission Tariff or PJM Tariff shall mean the tariff for transmission service within the PJM Region, as in effect from time to time, including any schedules, appendices, or exhibits attached thereto.

1.67 PJM Region

PJM Region shall have the same meaning as provided in the Operating Agreement.

1.68 PJM Region Installed Reserve Margin

PJM Region Installed Reserve Margin shall mean the percent installed reserve margin for the PJM Region required pursuant to this Agreement, as approved by the PJM Board pursuant to Schedule 4.1.

1.69 Planned Demand Resource

Planned Demand Resource shall mean a Demand Resource that does not currently have the capability to provide a reduction in demand or to otherwise control load, but that is scheduled to be capable of providing such reduction or control on or before the start of the Delivery Year for which such resource is to be committed, as determined in accordance with the requirements of Schedule 6.

1.69A Planned External Generation Capacity Resource

Planned External Generation Capacity Resource shall mean a proposed Generation Capacity Resource, or a proposed increase in the capability of a Generation Capacity Resource, that (a) is to be located outside the PJM Region, (b) participates in the generation interconnection process of a Control Area external to PJM, (c) is scheduled to be physically and electrically interconnected to the transmission facilities of such Control Area on or before the first day of the Delivery Year for which such resource is to be committed to satisfy the reliability requirements of the PJM Region, and (d) is in full commercial operation prior to the first day of such Delivery Year, such that it is sufficient to provide the Installed Capacity set forth in the Sell Offer forming the basis of such resource's commitment to the PJM Region. Prior to participation in any Reliability Pricing Model Auction for such Delivery Year, the Capacity Market Seller must demonstrate that it has executed an interconnection agreement (functionally equivalent to a System Impact Study Agreement under the PJM Tariff for Base Residual Auction and an Interconnection Service Agreement under the PJM Tariff for Incremental Auction) with the transmission owner to whose transmission facilities or distribution facilities the resource is being directly connected, and if applicable the transmission provider. A Planned External Generation Capacity Resource must provide evidence to PJM that it has been studied as a Network Resource, or such other similar interconnection product in such external Control Area, must provide contractual evidence that it has applied for or purchased transmission service to be deliverable to the PJM border, and must provide contractual evidence that it has applied for transmission service to be deliverable to the bus at which energy is to delivered, the agreements for which must have been executed prior to participation in any Reliability Pricing Model Auction for such Delivery Year. An External Generation Capacity Resource shall cease to be considered a Planned External Generation Capacity Resource as of the earlier of (i) the date that interconnection service commences as to such resource; or (ii) the resource has cleared an RPM Auction, in which case it shall become an Existing Generation Capacity Resource for purposes of the mitigation of offers for any RPM Auction for all subsequent Delivery Years.

1.70 Planned Generation Capacity Resource

Planned Generation Capacity Resource shall mean a Generation Capacity Resource participating in the generation interconnection process under Part IV, Subpart A of the PJM

Tariff, for which: (i) Interconnection Service is scheduled to commence on or before the first day of the Delivery Year for which such resource is to be committed to RPM or to an FRR Plan; (ii) a System Impact Study Agreement has been executed prior to the Base Residual Auction for such Delivery Year; (iii) an Interconnection Service Agreement has been executed prior to any Incremental Auction for such Delivery Year in which such resource plans to participate; and (iv) no megawatts of capacity have cleared an RPM Auction for any prior Delivery Year. For purposes of the must-offer requirement and mitigation of offers for any RPM Auction for a Delivery Year, a Generation Capacity Resource shall cease to be considered a Planned Generation Capacity Resource as of the earlier of (i) the date that Interconnection Service commences as to such resource; or (ii) the resource has cleared an RPM Auction for any Delivery Year, in which case it shall become an Existing Generation Capacity Resource for any RPM Auction for all subsequent Delivery Years. Notwithstanding the foregoing, a Generation Capacity Resource for which construction has not commenced and which would otherwise have been treated as a Planned Generation Capacity Resource but for the fact that it was bid into RPM Auctions for at least two consecutive Delivery Years, and cleared the last such auction only because it was considered existing and its mitigated offer cap was accepted when its price offer would not have otherwise been accepted, shall be deemed to be a Planned Generation Capacity Resource.

1.71 Planning Period

Planning Period shall mean the 12 months beginning June 1 and extending through May 31 of the following year, or such other period approved by the Members Committee.

1.72 Public Power Entity

Public Power Entity shall mean any agency, authority, or instrumentality of a state or of a political subdivision of a state, or any corporation wholly owned by any one or more of the foregoing, that is engaged in the generation, transmission, and/or distribution of electric energy.

1.73 Qualifying Transmission Upgrades

Qualifying Transmission Upgrades shall have the meaning specified in Attachment DD to the PJM Tariff.

1.74 [Reserved for Future Use]

1.75 Reliability Principles and Standards

Reliability Principles and Standards shall mean the principles and standards established by NERC or an Applicable Regional Reliability Council to define, among other things, an acceptable probability of loss of load due to inadequate generation or transmission capability, as amended from time to time.

1.76 Required Approvals

Required Approvals shall mean all of the approvals required for this Agreement to be modified or to be terminated, in whole or in part, including the acceptance for filing by FERC and every other regulatory authority with jurisdiction over all or any part of this Agreement.

1.77 Self-Supply

Self Supply shall have the meaning provided in Attachment DD to the PJM Tariff.

1.78 [Reserved for Future Use]

1.79 South RAA

South RAA shall mean that certain Reliability Assurance Agreement among Load-Serving Entities in the PJM South Region, on file with FERC as PJM Rate Schedule FERC No. 40.

1.80 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.

1.81 State Regulatory Structural Change

State Regulatory Structural Change shall mean as to any Party, a state law, rule, or order that, after September 30, 2006, initiates a program that allows retail electric consumers served by such Party to choose from among alternative suppliers on a competitive basis, terminates such a program, expands such a program to include classes of customers or localities served by such Party that were not previously permitted to participate in such a program, or that modifies retail electric market structure or market design rules in a manner that materially increases the likelihood that a substantial proportion of the customers of such Party that are eligible for retail choice under such a program (a) that have not exercised such choice will exercise such choice; or (b) that have exercised such choice will no longer exercise such choice, including for example, without limitation, mandating divestiture of utility-owned generation or structural changes to such Party's default service rules that materially affect whether retail choice is economically viable.

1.82 Threshold Quantity

Threshold Quantity shall mean, as to any FRR Entity for any Delivery Year, the sum of (a) the Unforced Capacity equivalent (determined using the Pool-Wide Average EFORD) of the Installed Reserve Margin for such Delivery Year multiplied by the Preliminary Forecast Peak

Load for which such FRR Entity is responsible under its FRR Capacity Plan for such Delivery Year, plus (b) the lesser of (i) 3% of the Unforced Capacity amount determined in (a) above or (ii) 450 MW. If the FRR Entity is not responsible for all load within a Zone, the Preliminary Forecast Peak Load for such entity shall be the FRR Entity's Obligation Peak Load last determined prior to the Base Residual Auction for such Delivery Year, times the Base FRR Scaling Factor (as determined in accordance with Schedule 8.1).

1.83 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.

1.84 Transmission Owner

Transmission Owner shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

1.85 Transmission Owners Agreement

Transmission Owners Agreement shall mean that certain Consolidated Transmission Owners Agreement, dated as of December 15, 2005 and as amended from time to time, among transmission owners within the PJM Region.

1.86 Unforced Capacity

Unforced Capacity shall mean installed capacity rated at summer conditions that is not on average experiencing a forced outage or forced derating, calculated for each Capacity Resource on the 12-month period from October to September without regard to the ownership of or the contractual rights to the capacity of the unit.

1.87 West RAA

West RAA shall mean the "PJM West Reliability Assurance Agreement among the Load Serving Entities in the PJM West Region," on file with FERC as PJM Rate Schedule FERC No. 32.

1.88 Zonal Capacity Price

Zonal Capacity Price shall mean the price of Unforced Capacity in a Zone that an LSE that has not elected the FRR Alternative is obligated to pay for a Delivery Year as determined pursuant to Attachment DD to the PJM Tariff.

1.89 Zone

Zone shall mean an area within the PJM Region, as set forth in Schedule 15, or as such areas may be (i) combined as a result of mergers or acquisitions or (ii) added as a result of the expansion of the boundaries of the PJM Region. A Zone shall include any Non-Zone Network Load (as defined in the PJM Tariff) located outside the PJM Region that is served from such Zone under Schedule H-A of the PJM Tariff.

ARTICLE 2 -- PURPOSE

This Agreement is intended to ensure that adequate Capacity Resources, including planned and Existing Generation Capacity Resources, planned and existing Demand Resources, Energy Efficiency Resources, and ILR will be planned and made available to provide reliable service to loads within the PJM Region, to assist other Parties during Emergencies and to coordinate planning of such resources consistent with the Reliability Principles and Standards. Further, it is the intention and objective of the Parties to implement this Agreement in a manner consistent with the development of a robust competitive marketplace. To accomplish these objectives, this Agreement is among all of the Load Serving Entities within the PJM Region. Unless this Agreement is terminated as provided in Section 3.3, every entity which is or will become a Load Serving Entity within the PJM Region is to become and remain a Party to this Agreement or to an agreement (such as a requirements supply agreement) with a Party pursuant to which that Party has agreed to act as the agent for the Load Serving Entity for purposes of satisfying the obligations under this Agreement related to the load within the PJM Region of that Load Serving Entity. Nothing herein is intended to abridge, alter or otherwise affect the emergency powers the Office of the Interconnection may exercise under the Operating Agreement and PJM Tariff.

5.2 Breach by a Party.

The provisions of Section 15.1 of the Operating Agreement shall apply to a Party's (a) failure to pay any amount due under this Agreement when due or (b) breach of any material obligation under this Agreement. In addition to the remedies available to the Office of the Interconnection set forth in Section 15.1 of the Operating Agreement, if the Party fails to cure such non-payment or breach, the Office of the Interconnection and the remaining Parties may, without an election of remedies, exercise all remedies available at law or in equity or other appropriate proceedings. Such proceedings may include (a) the commencement of a proceeding before the appropriate state regulatory commission(s) to request suspension or revocation of the breaching Party's license or authorization to serve retail load within the state(s) and/or (b) bringing any civil action or actions or recovery of damages that may include, but not be limited to, all amounts due and unpaid by the breaching Party, and all costs and expenses reasonably incurred in the exercise of its remedies hereunder (including, but not limited to, reasonable attorneys' fees).

8.1 Nature of Charges.

Upon the advice and recommendations of the Members Committee, the PJM Board shall, subject to any Required Approvals, approve certain charges to be imposed on a Party for its failure to satisfy its obligations under this Agreement, as set forth in this Agreement.

8.2 Determination of Charge Amounts.

No later than April 1 of each year, the Members Committee shall recommend to the PJM Board such charges to be applicable under this Agreement during the following Planning Period , which, upon approval by the PJM Board, shall be modified accordingly, subject to the receipt of all Required Approvals. The Markets and Reliability Committee may establish projected charges for estimating purposes only.

9.1 Overall Coordination.

Each Party shall cooperate with the other Parties in the coordinated planning and operation of their owned or contracted for Capacity Resources to obtain a degree of reliability consistent with the Reliability Principles and Standards. In furtherance of such cooperation each Party shall:

(a)

cooperate with the members and associate members of such Party's Applicable Regional Reliability Council to ensure the reliability of the region;

(b) make available its Capacity Resources to the other Parties through the Office of the Interconnection for coordinated operation and to supply the needs of the PJM Region for Operating Reserves;

(c) provide or arrange for Network Transmission Service or Firm Point-to-Point Transmission Service for service to the projected load of the Party and include all Capacity Resources as Network Resources designated pursuant to the PJM Tariff or Points of Receipt for Firm Point-to-Point Transmission Service;

(d) provide or arrange for sufficient reactive capability and voltage control facilities to meet Good Utility Practice and to be consistent with the Reliability Principles and Standards;

(e) implement emergency procedures and take such other coordination actions as may be necessary in accordance with the directions of the Office of the Interconnection in times of Emergencies; and

(f) maintain or arrange for Black Start Capability for a portion of its Capacity Resources at least equal to that established from time-to-time by the Office of the Interconnection.

9.3 Data Submissions.

Each Party shall submit to the Office of the Interconnection the data and other information necessary for the performance of this Agreement as may be more fully described, in Schedule 11 hereof.

9.4 Charges for Failures to Comply.

(a) An emergency procedure charge, as set forth in Attachment DD to the PJM Tariff, shall be imposed on any Party that fails to comply with the directions of the Office of the Interconnection in times of Emergencies.

(b) A data submission charge, as set forth in Schedule 12, shall be imposed on any Party that fails to submit the data, plans or other information required by this Agreement in a timely or accurate manner as provided in Schedule 11.

SCHEDULE 7

PLANS TO MEET OBLIGATIONS

A. Each Party that elects to meet its estimated obligations for a Delivery Year by Self-Supply of Capacity Resources shall notify the Office of the Interconnection via the Internet site designated by the Office of the Interconnection, prior to the start of the Base Residual Auction for such Delivery Year.

B. A Party that Self-Supplies Capacity Resources to satisfy its obligations for a Delivery Year must submit a Sell Offer as to such resource in the Base Residual Auction for such Delivery Year, in accordance with Attachment DD to the PJM Tariff.

C. If, at any time after the close of the Third Incremental Auction for a Delivery Year, including at any time during such Delivery Year, a Capacity Resource that a Party has committed as a Self-Supplied Capacity Resource becomes physically incapable of delivering capacity or reducing load, the Party may submit a replacement Capacity Resource to the Office of the Interconnection. Such replacement Capacity Resource (1) may not be previously committed for such Delivery Year, (2) shall be capable of providing the same quantity of megawatts of capacity or load reduction as the originally committed Capacity Resource, and (3) shall meet the same locational requirements, if applicable, as the originally committed resource. In accordance with Attachment DD to the PJM Tariff, the Office of the Interconnection shall determine the acceptability of the replacement Capacity Resource.

B. Eligibility

1. A Party is eligible to select the FRR Alternative if it (a) is an IOU, Electric Cooperative, or Public Power Entity; and (b) demonstrates the capability to satisfy the Unforced Capacity obligation for all load in an FRR Service Area, including all expected load growth in such area, for the term of such Party's participation in the FRR Alternative.

2. A Party eligible under B.1 above may select the FRR Alternative only as to all of its load in the PJM Region; provided however, that a Party may select the FRR Alternative for only part of its load in the PJM Region if (a) the Party elects the FRR Alternative for all load (including all expected load growth) in one or more FRR Service Areas; (b) the Party complies with the rules and procedures of the Office of the Interconnection and all relevant Electric Distributors related to the metering and reporting of load data and settlement of accounts for separate FRR Service Areas; and (c) the Party separately allocates its Capacity Resources to and among FRR Service Areas in accordance with rules specified in the PJM Manuals.

E. Conditions on Purchases and Sales of Capacity Resources by FRR Entities

1. An FRR Entity may not include in its FRR Capacity Plan for any Delivery Year any Capacity Resource that has cleared in any auction under Attachment DD of the PJM Tariff for such Delivery Year. Nothing herein shall preclude an FRR Entity from including in its FRR Capacity Plan any Capacity Resource that has not cleared such an auction for such Delivery Year. Furthermore, nothing herein shall preclude an FRR Entity from including in its FRR Capacity Plan a Capacity Resource obtained from a different FRR Entity, provided, however, that each FRR Entity shall be individually responsible for meeting its capacity obligations hereunder, and provided further that the same megawatts of Unforced Capacity shall not be committed to more than one FRR Capacity Plan for any given Delivery Year.

2. An FRR Entity that designates Capacity Resources in its FRR Capacity Plan(s) for a Delivery Year based on the Threshold Quantity may offer to sell Capacity Resources in excess of that needed for the Threshold Quantity in any auction conducted under Attachment DD of the PJM Tariff for such Delivery Year, but may not offer to sell Capacity Resources in the auctions for any such Delivery Year in excess of an amount equal to the lesser of (a) 25% times the Unforced Capacity equivalent of the Installed Reserve Margin for such Delivery Year multiplied by the Preliminary Forecast Peak Load for which such FRR Entity is responsible under its FRR Capacity Plan(s) for such Delivery Year, or (b) 1300 MW.

3. An FRR Entity that designates Capacity Resources in its FRR Capacity Plan(s) for a Delivery Year based on the Threshold Quantity may not offer to sell such resources in any Reliability Pricing Model auction, but may use such resources to meet any increased capacity obligation resulting from unanticipated growth of the loads in its FRR Capacity Plan(s), or may sell such resources to serve loads located outside the PJM Region, or to another FRR Entity, subject to subsection E.1 above.

4. A Party that has selected the FRR Alternative for only part of its load in the PJM Region pursuant to Section B.2 of this Schedule that designates Capacity Resources as Self-Supply in a Reliability Pricing Model Auction to meet such Party's expected Daily Unforced Capacity Obligation under Schedule 8 shall not be required, solely as a result of such designation, to identify Capacity Resources in its FRR Capacity Plan(s) based on the Threshold Quantity; provided, however, that such Party may not so designate Capacity Resources in an amount in excess of the lesser of (a) 25% times such Party's total expected Unforced Capacity obligation (under both Schedule 8 and Schedule 8.1), or (b) 200 MW. A Party that wishes to avoid the foregoing limitation must identify Capacity Resources in its FRR Capacity Plan(s) based on the Threshold Quantity.

G. Capacity Resource Performance

Any Capacity Resource committed by an FRR Entity in an FRR Capacity Plan for a Delivery Year shall be subject during such Delivery Year to the charges set forth in sections 7, 9, 10, 11, and 13 of Attachment DD to the PJM Tariff; provided, however, the Daily Deficiency Rate under sections 7, 9, and 13 thereof shall be 1.20 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions), and the charge rates under section 10 thereof, shall be the Capacity Resource Clearing Price resulting from the RPM Auctions for the Delivery Year for the LDA encompassing the Zone of the FRR Entity, weight-averaged as described above. An FRR Entity shall have the same opportunities to cure deficiencies and avoid or reduce associated charges during the Delivery Year that a Market Seller has under Sections 7, 9, and 10 of Attachment DD to the PJM Tariff. An FRR Entity may cure deficiencies and avoid or reduce associated charges prior to the Delivery Year by procuring replacement Unforced Capacity outside of any RPM Auction and committing such capacity in its FRR Capacity Plan.

SCHEDULE 10.1

LOCATIONAL DELIVERABILITY AREAS AND REQUIREMENTS

The capacity obligations imposed under this Agreement recognize the locational value of Capacity Resources. To ensure that such locational value is properly recognized and quantified, the Office of the Interconnection shall follow the procedures in this Schedule.

A. The Locational Deliverability Areas for the purposes of determining locational capacity obligations hereunder, but not necessarily for the purposes of the Regional Transmission Expansion Planning Protocol, shall consist of the following Zones (as defined in Schedule 15), combinations of such Zones, and portions of such Zones:

- ATSI
- *DEOK*
- Dominion
- Penelec
- ComEd
- AEP
- Dayton
- Duquesne
- APS
- AE
- BGE
- DPL
- PECO
- PEPCO
- PSEG
- JCPL
- MetEd
- PPL
- Mid-Atlantic Area Council (MAAC) Region (consisting of all the zones listed below for Eastern MAAC, Western MAAC, and Southwestern MAAC)
- ComEd, AEP, Dayton, APS, Duquesne, ATSI, *and DEOK*
- Eastern MAAC (PSE&G, JCP&L, PECO, AE, DPL & RE)
- Southwestern MAAC (PEPCO & BG&E)
- Western MAAC (Penelec, MetEd, PPL)
- PSEG northern region (north of Linden substation); and
- DPL southern region (south of Chesapeake and Delaware Canal

The Locational Deliverability Areas for the purposes of determining locational capacity obligations hereunder, but not necessarily for the purposes for the Regional Transmission Expansion Planning Protocol, shall also include any new Zones expected to be integrated into PJM prior to the commencement of the Base Residual Auction for the Delivery Year for which the locational capacity obligation is being determined.

B. For purposes of evaluating the need for any changes to the foregoing list, Locational Deliverability Areas shall be those areas, identified by the load deliverability analyses conducted pursuant to the Regional Transmission Expansion Planning Protocol and the PJM Manuals that have a limited ability to import capacity due to physical limitations of the transmission system, voltage limitations or stability limitations. Such limits on import capability shall not reflect the effect of Qualifying Transmission Upgrades offered in the Base Residual Auction. The Locational Deliverability Areas identified in Paragraph A above (as it may be amended from time to time) for a Delivery Year shall be modeled in the Base Residual Auction and any Incremental Auction conducted for such Delivery Year. If the Office of the Interconnection includes a new Locational Deliverability Area in the Regional Transmission Expansion Planning Protocol, it shall make a filing with FERC to amend this Schedule to add a new Locational Deliverability Area (including a new aggregate LDA), if such new Locational Deliverability Area is projected to have a capacity emergency transfer limit less than 1.15 times the capacity emergency transfer objective of such area, or if warranted by other reliability concerns consistent with the Reliability Principles and Standards. In addition, any Party may propose, and the Office of the Interconnection shall evaluate, consistent with the same CETO/CETO comparison or other reliability concerns, possible new Locational Deliverability Areas (including aggregate LDAs) for inclusion under the Regional Transmission Expansion Planning Protocol and for purposes of determining locational capacity obligations hereunder.

C. For each Locational Deliverability Area for which a separate VRR Curve was established for a Delivery Year, the Office of the Interconnection shall determine, pursuant to procedures set forth in the PJM Manuals, the Percentage of Internal Resources Required, that must be committed during such Delivery Year from Capacity Resources physically located in such Locational Deliverability Area.

SCHEDULE 11

DATA SUBMITTALS

To perform the studies required to determine the Forecast Pool Requirement and Daily Unforced Capacity Obligations under this Agreement and to determine compliance with the obligations imposed by this Agreement, each Party and other owner of a Capacity Resource shall submit data to the Office of the Interconnection in conformance with the following minimum requirements:

1. All data submitted shall satisfy the requirements, as they may change from time to time, of any procedures adopted by the Members Committee.

2. Data shall be submitted in an electronic format, or as otherwise specified by the Markets and Reliability Committee and approved by the PJM Board.

3. Actual outage data for each month for Generator Forced Outages, Generator Maintenance Outages and Generator Planned Outages shall be submitted so that it is received by such date specified in the PJM Manuals.

4. On or before the date specified in the PJM Manuals, planned and maintenance outage data for all Generation Resources shall be submitted.

The Parties acknowledge that additional information required to determine the Forecast Pool Requirement is to be obtained by the Office of the Interconnection from Electric Distributors in accordance with the provisions of the Operating Agreement.

SCHEDULE 13

EMERGENCY PROCEDURE CHARGES

Following an Emergency, the compliance of each Party with the instructions of the Office of the Interconnection shall be evaluated as recommended by the Markets and Reliability Committee and directed by the PJM Board. If, based on such evaluation, it is determined that a Party refused to comply with, or otherwise failed to employ its best efforts to comply with, the instructions of the Office of the Interconnection to implement PJM emergency procedures, that Party shall pay an emergency procedure charge, as set forth in Attachment DD to the PJM Tariff. The revenue associated with Emergency Procedure Charges shall be allocated in accordance with Attachment DD to the PJM Tariff.

SCHEDULE 14

DELEGATION TO THE OFFICE OF THE INTERCONNECTION

The following responsibilities shall be delegated by the Parties to the Office of the Interconnection:

1. New Parties. With regard to the addition, withdrawal or removal of a Party the Office of the Interconnection shall:

   (a) Receive and evaluate the information submitted by entities that plan to serve loads within the PJM Region, including entities whose participation in the Agreement will expand the boundaries of the PJM Region. Such evaluation shall be conducted in accordance with the requirements of the Agreement.

   (b) Evaluate the effects of the withdrawal or removal of a Party from this Agreement.

2. Implementation of Reliability Assurance Agreement. With regard to the implementation of the provisions of this Agreement the Office of the Interconnection shall:

   (a) Receive all required data and forecasts from the Parties and other owners or providers of Capacity Resources;

   (b) Perform all calculations and analyses necessary to determine the Forecast Pool Requirement and the capacity obligations imposed under the Reliability Assurance Agreement, including periodic reviews of the capacity benefit margin for consistency with the Reliability Principles and Standards;

   (c) Monitor the compliance of each Party with its obligations under the Agreement;

   (d) Keep cost records, and bill and collect any costs or charges due from the Parties and distribute those charges in accordance with the terms of the Agreement;

   (e) Assist with the development of rules and procedures for determining and demonstrating the capability of Capacity Resources;

   (f) Establish the capability and deliverability of Generation Capacity Resources consistent with the requirements of the Reliability Assurance Agreement;

(g) Establish standards and procedures for Planned Demand Resources;

(h) Collect and maintain generator availability data;

(i) Perform any other forecasts, studies or analyses required to administer the Agreement;

(j) Coordinate maintenance schedules for generation resources operated as part of the PJM Region;

(k) Determine and declare that an Emergency exists or has ceased to exist in all or any part of the PJM Region or announce that an Emergency exists or ceases to exist in a Control Area interconnected with the PJM Region;

(l) Enter into agreements for (i) the transfer of energy in Emergencies in the PJM Region or in a Control Area interconnected with the PJM Region and (ii) mutual support in such Emergencies with other Control Areas interconnected with the PJM Region; and

(m) Coordinate the curtailment or shedding of load, or other measures appropriate to alleviate an Emergency, to preserve reliability in accordance with FERC, NERC or Applicable Regional Reliability Council principles, guidelines, standards, requirements and the PJM Manuals, and to ensure the operation of the PJM Region in accordance with Good Utility Practice.