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April 12, 2013

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

Re: *PJM Interconnection, L.L.C.*, Docket No. ER13-1278-000

Dear Ms. Bose:

Pursuant to Section 205 of the Federal Power Act, 16 U.S.C. § 824d, and Section 35.13 of the regulations of the Federal Energy Regulatory Commission (“FERC” or the “Commission”), 18 C.F.R. Part 35, PJM Interconnection, L.L.C. (“PJM”) hereby submits for filing revised sheets of the Open Access Transmission Tariff (“Tariff”) and the Amended and Restated Operating Agreement of PJM (“Operating Agreement”).¹ The purpose of the proposed revisions are to correct identified non-substantive errors and make clarifications to several market settlements related rules found in the Tariff and corresponding provisions of the Operating Agreement. PJM respectfully requests that the Commission accept the proposed revisions for filing, allowing them to become effective on June 14, 2013.

I. Background

In 2012, PJM launched a quality assurance initiative, referred to internally as the Market Settlements Formulation Review Project (“Settlements Project”), which was tasked with a comprehensive review of PJM’s market settlements processes and procedures to ensure proper implementation of those requirements and also to identify suggested improvements to those documents which would enhance clarity. The initial phase of this project reviewed approximately 362 markets rules provisions across 162 requirements documents that impacted nearly 1,600 market settlement calculation system formulations, and identified a host of potential clarifications and corrections to PJM’s market settlement rules. Many of these identified clarifications or corrections have been incorporated, where possible, in existing PJM filings; however, PJM has not been able to include the proposed changes offered in this filing with any

¹ Capitalized terms not otherwise defined herein have the meaning specified in the PJM Operating Agreement or the PJM Open Access Transmission Tariff, as appropriate.

of its existing filings and offers them here to ensure that the corrections and clarifications are implemented on a timely basis. Each suggested revision is discussed further below.

II. The Proposed Revisions

A. Treatment of Negative FTR Allocations

In defining the calculation of Transmission Congestion Credits for Market Participants, Section 5.2.5(a) of the Appendix to Attachment K of PJM's Tariff and corresponding section in Attachment A of PJM's Operating Agreement, state that the total of all the FTR Target Allocations determined in accordance with PJM's market rules will be compared to the total Transmission Congestion Charges in each hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market. In practice, and as specified in PJM's manuals, which are used to provide further specificity regarding Tariff and Operating Agreement rules and procedures, PJM uses the total of all the *positive* Target Allocations (*i.e.*, excluding any negative Target Allocations from the calculation) to make the comparison to determine whether a Market Participant is entitled to Transmission Congestion Credits. As the language exists in the Tariff and Operating Agreement today, this distinction is not apparent. Accordingly, PJM proposes to change Section 5.2.5(a) to clarify that, in accordance with its current practice, it will only consider the total of all the *positive* Target Allocations determined in accordance with PJM market rules in calculating a participant's Transmission Congestion Credit.

B. Netting of Balancing Operating Reserve Charges

Section 3.2.3 of the Appendix to Attachment K of PJM's Tariff and corresponding section in Attachment A of PJM's Operating Agreement, spell out the market rules for obtaining, and compensating, Operating Reserves from Market Sellers. Historically, in calculating a Market Seller's appropriate Balancing Operating Reserve credits, PJM's Manuals, and its Market Settlements Calculation System ("MSCS"), have consistently, and explicitly, net the value of energy in the Day-ahead Energy Market from those Balancing Operating Reserve credits to be provided to the Market Seller. However, during the Settlements Project, it was identified the explicit netting of the Day-ahead energy value was inadvertently removed from the Tariff and Operating Agreement in a prior filing implementing segmented make-whole Balancing Operating Reserve payments which was made in 2008.² Prior to this inadvertent change, the Tariff and Operating Agreement explicitly stipulated the deduction of the value of energy in the Day-ahead market from the resulting Balancing Operating Reserve credits. Accordingly, PJM proposes to change Section 3.2.3(e) to, once again, explicitly provide for the deduction of Day-ahead energy values from any Balancing Operating Reserve credits received by Market Sellers.

² See, *PJM Interconnection, L.L.C.*, Docket No. ER08-1569-000 (September 24, 2008).

C. Determination of Balancing Operating Reserve Deviation Quantity for Units That are not Dispatchable

Section 3.2.3(o) of the Appendix to Attachment K of PJM's Tariff and corresponding section in Attachment A of the PJM's Operating Agreement, the market rules for determining Balancing Operating Reserve deviation quantity for units that are not dispatchable are stated. The Tariff and the Operating Agreement specify that the Balancing Operating Reserve deviations for resources that are not dispatchable in both the Day-ahead and Real-time markets should be assessed as "hourly integrated Real-time MWh *and* Day-ahead MWh"(emphasis supplied). The inclusion of the conjunctive "and," could be misinterpreted by a market participant as requiring PJM to add together the hourly integrated Real-time MWh and Day-ahead MWh in determining deviation quantities for these units; however, because this formulation is used to derive deviations such a calculation would be incorrect. As such, PJM's market settlement's system correctly formulates the deviation quantity as the real-time MWh *less* the day-ahead MWh. Accordingly, PJM proposes to amend Section 3.2.3(o) to explicitly state that the deviations for resources that are not dispatchable in both the day-ahead and real-time markets should be assessed as "hourly integrated Real-time MWh *less* Day-ahead MWh."(emphasis supplied).

D. Netting LMP From Synchronized Reserve Credit

In calculating Tier 1 synchronized reserve credits Section 3.2.3A of PJM's Tariff, and corresponding Section of Attachment A of the Operating Agreement, specifies the calculation as the MWh of increased output (or decreased consumption) provided during a synchronized reserve event multiplied by the average of the five minute Locational Marginal Prices ("LMPs") over the duration of the synchronized reserve event, plus a dollar per MWh "adder." PJM's settlement system follows this same calculation; however it additionally nets the hourly integrated real-time LMP from the price applied to MWh of synchronized reserve provided to avoid double counting of spot market energy credits for the hour. Because the netting of integrated real-time LMP is appropriate to avoid over collection of synchronized reserve credits, PJM has proposed to make this provision explicit in its proposed Tariff and Operating Agreement provisions.

E. Balancing Operating Reserves Lost Opportunity Cost Credits for Diesel Units

PJM's Tariff and Operating Agreement prescribes the Balancing Operating Reserves Lost Opportunity Cost ("LOC") credit calculations to apply specifically to combustion turbine ("CT"), steam-electric and combined cycle units. However, these provisions do not specify whether, or how, such LOC credits should be calculated for diesel units. Because of their similar operating characteristics, PJM has historically considered diesel units as CTs for the purposes of calculating Balancing Operating Reserve LOC credits. In fact, PJM has historically treated diesel and CT units synonymously for many other purposes and except for one instance in the PJM Tariff in Schedule 6A, has not referred to those units separately in its governing documents. In order to avoid confusion by potentially creating a presumption that diesel and CT units should be treated differently (by referring to them explicitly and separately in Schedule 6A of the Tariff), PJM has proposed to remove the single explicit reference to diesel units in the PJM

Tariff and clarify in its internal procedures that, unless specifically stated otherwise in the PJM Tariff or other agreements, manuals or procedures, diesel units shall be considered as CT units for market settlement purposes. Accordingly, PJM proposes to remove the term “diesel” from Schedule 6A of the PJM Tariff.

III. Stakeholder Support

On February 28, 2013, the PJM Members Committee met and endorsed the proposed Tariff revisions with no Members opposed or abstaining.

Similarly, on February 28, 2013, the PJM Members Committee approved the proposed Operating Agreement revision with no Members opposed or abstaining.

IV. Effective Date

Consistent with the Commission’s notice requirements, PJM requests an effective date of June 14, 2013, which is at least 60 days from the date of this filing.

V. Documents Submitted

Along with this transmittal letter, PJM submits electronic versions of the revisions to the Tariff and Operating Agreement in both marked (showing the changes) and clean forms.

VI. Correspondence and Communication

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

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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. Electronic service is permitted as of November 3, 2008, under the Commission’s regulations³ pursuant to Order No. 714⁴ and the Commission’s Notice of Effectiveness of Regulations issued on October

³ See, 18 C.F.R. §§ 35.2, 154.2, 154.208 and 341.2.

⁴ *Electronic Tariff Filings*, Order No. 714, 124 FERC ¶ 61,270

28, 2008, in Docket No. RM01-5-000. In compliance with those regulations, PJM will post a copy of this filing to the FERC filings section of the 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 Region⁵ alerting them that this filing has been made by PJM today and 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 Commission's eLibrary website located at the following link: <http://www.ferc.gov/docs-filing/elibrary.asp> in accordance with the Commission's regulations and Order No. 714.

Respectfully submitted,



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⁵ PJM already maintains updates and regularly uses e-mail lists for all PJM Members and affected commissions.

Attachment A

Revisions to the PJM Open Access Transmission Tariff and PJM Operating Agreement

(Marked / Redline Format)

Section(s) of the
PJM Open Access Transmission Tariff
(Marked / Redline Format)

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 Black Start Service revenue requirements and 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, with a copy to the Office of the Interconnection, by no later than May 3 of each year. The Market Monitoring Unit and the Black Start Unit owner shall attempt to come to agreement on the level of each component included in the Black Start Service revenue requirements by no later than May 14 of each year. By no later than May 21 of each year, the Black Start Unit owner shall notify the Office of the Interconnection and the Market Monitoring Unit in writing whether it agrees or disagrees with the Market Monitoring Unit's determination of the level of each component included in the Black Start Service revenue requirements. The Black Start Unit owner may also submit Black Start Service revenue requirements that it chooses to the Office of the Interconnection by no later than May 21 of each year, 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 Unit 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 and PJM Manuals.

The Office of the Interconnection shall determine whether to accept the values submitted by the Black Start Unit owner subject to the requirements of the Tariff and the PJM Manuals by no later than May 27. If the Office of the Interconnection does not accept the values submitted by the Black Start Unit owner in such case, the Black Start Unit 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 Unit owner in such case, the Market Monitoring Unit may petition the Commission for an order that would require the Black Start Unit owner to utilize the values determined by the Market Monitoring Unit or the Office of the Interconnection or such other values as determined by the Commission. The annual calculation of Black Start Service revenue requirements shall become effective on June 1 of each year, except that 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. Notwithstanding the foregoing, the deadlines set forth in this section 17 shall not apply to a Black Start Unit owner's election to select a new method of recovery for its Fixed BSSC.

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

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

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

$$(\text{Training Costs}) * (1 + Z)$$

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:

$$\text{Net CONE} * \text{Black Start Unit Capacity} * X$$

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

$$(\text{Net Cone} * \text{Black Start NERC-CIP Unit Capacity} * X) + (\text{Incremental Black Start NERC-CIP Capital Costs} * \text{CRF})$$

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. To the extent that a Black Start Unit owner is currently recovering black start costs pursuant to a FERC-approved rate, that cost recovery will be included as a formulaic component for calculating the Black Start Unit’s annual revenue requirement pursuant to this paragraph 18. However, under no circumstances will PJM or the Black Start Unit owner restructure or modify that existing FERC-approved rate without FERC approval.

“Incremental Black Start Capital Costs” are the new or additional capital costs 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 Unit 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.

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:

$$\text{Black Start Unit O\&M} * Y$$

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:

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

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 traded the first business day on or following May 1.

"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 reported the first business day on or following May 1.

"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 solely for Black Start Units with a commitment established under section 5 above and shall be ten percent. For those Black Start Units that elect to recover new or additional Black Start Capital Costs under section 6 above, the incentive factor, Z, shall be equal to zero.

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 criteria for Black Start Service and the criteria for Black Start Service in the Applicable Standards 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.

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 Internal 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 the following for Regulation dispatched by the Office of the Interconnection to meet such obligation: (i) the capability Regulation market-clearing price determined in accordance with subsection (h) of this section; (ii) the amounts, if any, described in subsection (f) of this section; and (iii) the performance Regulation market-clearing price determined in accordance with subsection (g) of this section.

(b) Each Market Seller and Generating Market Buyer shall be credited for each of its resources supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection such that the calculated credit for each increment of Regulation provided by each resource shall be the higher of: (i) the Regulation market-clearing price; or (ii) the sum of the applicable Regulation offers for a resource determined pursuant to Section 3.2.2A.1 of this Schedule, the unit-specific shoulder hour opportunity costs described in subsection (e) of this section, the unit-specific inter-temporal opportunity costs, and the unit-specific opportunity costs discussed in subsection (d) of this section.

(c) The total 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. In accordance with the PJM Manuals, the total Regulation market-clearing price shall be calculated by optimizing the dispatch profile to obtain the lowest cost combination set of resources that satisfies the Regulation requirement. The market-clearing price for each regulating hour shall be equal to the average of all 5-minute clearing prices calculated during that hour. The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource 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 3.2.2A.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 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, 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.

For hydroelectric resources offering to sell Regulation in a regulating hour, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the full value of the Locational Marginal Price at that generation bus for each megawatt of Regulation capability.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the expected Locational Marginal Price at the generation bus for the hydroelectric resource and the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. Estimated opportunity costs shall be zero for hydroelectric resources for which the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those hours during which all available units at the hydroelectric resource were operating is higher than the actual Locational Marginal Price at the generator bus for the regulating hour.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating and the expected Locational Marginal Price at the generation bus for the hydroelectric resource. Estimated opportunity costs shall be zero for hydroelectric resources for which the actual Locational Marginal Price at the generator bus for the regulating hour is higher than the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those hours during which all available units at the hydroelectric resource were operating.

For the purpose of committing resources and setting Regulation market clearing prices, the Office of the Interconnection shall utilize day-ahead Locational Marginal Prices to calculate opportunity costs for hydroelectric resources. For the purposes of settlements, the Office of the Interconnection shall utilize the real-time Locational Marginal Prices to calculate opportunity costs for hydroelectric resources.

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

(e) In determining the credit under subsection (b) to a Market Seller or 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.

(g) To determine the performance Regulation market-clearing price for each Regulation Zone, the Office of the Interconnection shall adjust the submitted performance offer for each resource in accordance with the historical performance of that resource, the amount of Regulation that resource will be dispatched based on the ratio of control signals calculated by the Office of the Interconnection, and the unit-specific benefits factor described in subsection (j) of this section for which that resource is qualified. The maximum adjusted performance offer of all cleared resources will set the performance Regulation market-clearing price.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions, will be credited for Regulation performance *by multiplying* the assigned MW(s) by the performance Regulation market-clearing price, *by the ratio between the requested mileage for the Regulation dispatch signal assigned to the Regulation resource and the Regulation dispatch signal assigned to traditional resources*, and *by the Regulation resource's accuracy score* calculated in accordance with subsection (k) of this section.

(h) The Office of the Interconnection shall divide each Regulation resource's capability offer by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score for the resource for the purposes of committing resources and setting the market clearing prices.

The Office of the Interconnection shall calculate the capability Regulation market-clearing price for each Regulation Zone by subtracting the performance Regulation market-clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the capability Regulation market clearing price for that market hour.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions will be credited for Regulation capability based on the assigned MW and the capability Regulation market-clearing price multiplied by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(i) In accordance with the processes described in the PJM Manuals, the Office of the Interconnection shall: (i) calculate inter-temporal opportunity costs for each applicable resource; (ii) include such inter-temporal opportunity costs in each applicable resource's offer to sell

frequency Regulation service; and (iii) account for such inter-temporal opportunity costs in the Regulation market-clearing price.

(j) The Office of the Interconnection shall calculate a unit-specific benefits factor for each of the dynamic Regulation signal and traditional Regulation signal in accordance with the PJM Manuals. Each resource shall be assigned a unit-specific benefits factor based on their order in the merit order stack for the applicable Regulation signal. The unit-specific benefits factor is the point on the benefits factor curve that aligns with the last megawatt, adjusted by historical performance, that resource will add to the dynamic resource stack. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

(k) The Office of the Interconnection shall calculate each Regulation resource's accuracy score. The accuracy score shall be the average of a delay score, correlation score, and energy score for each ten second interval. For purposes of setting the interval to be used for the correlation score and delay scores, PJM will use the maximum of the correlation score plus the delay score for each interval.

The Office of the Interconnection shall calculate the correlation score using the following statistical correlation function (r) that measures the delay in response between the Regulation signal and the resource change in output:

$$\text{Correlation Score} = r_{\text{Signal, Response}(\delta, \delta+5 \text{ Min}); \\ \delta=0 \text{ to } 5 \text{ Min}}$$

where δ is delay.

The Office of the Interconnection shall calculate the delay score using the following equation:

$$\text{Delay Score} = \text{Abs} ((\delta - 5 \text{ Minutes}) / (5 \text{ Minutes})).$$

The Office of the Interconnection shall calculate a energy score as a function of the difference in the energy provided versus the energy requested by the Regulation signal while scaling for the number of samples. The energy score is the absolute error (ϵ) as a function of the resource's Regulation capacity using the following equations:

$$\text{Energy Score} = 1 - 1/n \sum \text{Abs (Error)};$$

$$\text{Error} = \text{Average of Abs} ((\text{Response} - \text{Regulation Signal}) / (\text{Hourly Average Regulation Signal})); \text{ and}$$

n = the number of samples in the hour and the energy.

The Office of the Interconnection shall calculate an accuracy score for each Regulation resource that is the average of the delay score, correlation score, and energy score for a five-minute period using the following equation where *the energy score, the delay score, and the correlation score are each weighted equally*:

$$\text{Accuracy Score} = \max ((\text{Delay Score}) + (\text{Correlation Score})) + (\text{Energy Score}).$$

The historic accuracy score will be based on a rolling average of the hourly accuracy scores, with consideration of the qualification score, as defined in the PJM Manuals.

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 *multiplied* by the historic accuracy score of the resource and multiplied by the unit-specific benefits factor for which the capability cost-based offer plus the performance 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.

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers is less than or equal to 1.0, then the three

suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

(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. PJM shall also (i) determine whether any resources were scheduled in the Day-ahead Energy Market to provide Black Start service, Reactive Services or transfer interface control during the Operating Day because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day in order to minimize the total cost of Operating Reserves associated with the provision of such services and reflect the most accurate possible expectation of real-time operating conditions in the day-ahead model, which resources would not have otherwise been committed in the day-ahead security-constrained dispatch and (ii) report on the day following the Operating Day the megawatt quantities scheduled in the Day-ahead Energy Market for the above-enumerated purposes for the entire RTO.

Except as provided in Section 3.2.3(n), 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, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load (net of operating Behind The Meter Generation) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

(e) 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 in as determined by the Real-time Day-ahead Energy Market plus any credit or change for quantity deviations, at PJM dispatch direction, from the Day-ahead Energy Market during the Operating Day 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), 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 Non-Synchronized Reserve in excess of the Non-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, Non-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, Non-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 $\{(LMP_{DMW} - AG) \times (URTLMP - UB)\}$, where:

LMP_{DMW} 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 and limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;

AG equals the actual hourly integrated output of the unit;

URLTLP 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 URLTLP - 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, *and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output*, if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described 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) $\{(URLTLP - UDALMP) \times DAG\}$, or (ii) $\{(URLTLP - UB) \times DAG\}$ where:

URLTLP 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 URLTLP - UDALMP and URLTLP - 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.

(f-4) A Market Seller's wind generating unit that is pool-scheduled or self-scheduled and operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the 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 $\{(LMPDMW - AG) \times (URTLMP - UB)\}$, where:

LMPDMW equals the lesser of the PJM forecasted output for the unit or 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, *and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output*;

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.

In the event the Office of the Interconnection experiences a technical problem or malfunction with its wind forecasting tool that results in an erroneous forecast for a wind resource during a period of time for which the wind resource is eligible for lost opportunity cost, the Office of the Interconnection and the Market Seller will attempt to reach a mutually agreeable forecast value for settlement purposes. If the Office of the Interconnection and the Market Seller do not come to mutual agreement on an acceptable forecast value, the Office of the Interconnection shall utilize the forecast value that it determines is appropriate.

(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, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (1) 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 in subsection (h)(ii) below and in the PJM Manuals; (2) 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; (3) 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 (4) 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.

The costs associated with scheduling of units for Black Start service or testing of Black Start Units shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff.

Notwithstanding section (h)(1) above, as more fully set forth in the PJM Manuals, load deviations from the Day-ahead Energy Market shall not be assessed Operating Reserves charges to the extent attributable to reductions in the load of Price Responsive Demand that is in response to an increase in Locational Marginal Price from the Day-ahead Energy Market to the Real-time Energy Market and that is in accordance with a properly submitted PRD Curve.

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 buses 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 buses 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.

(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 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 generation resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:

(i) real-time economic minimum $\leq$ 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum $\geq$ 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:

$$\text{Ramp_Request}_t = \frac{(\text{UDS}_{\text{target}}_{t-1} - \text{AOutput}_{t-1})}{(\text{UDSL}_{\text{time}}_{t-1})}$$

$$\text{RL_Desired}_t = \text{AOutput}_{t-1} + \left(\text{Ramp_Request}_t * \text{Case_Eff_time}_{t-1} \right)$$

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 generation resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the 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 its 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 $\leq 20\%$, 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.

(o-1) Dispatchable economic load reduction resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Economic load reduction resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations as described in this subsection and as further specified in the PJM Manuals.

The Desired MW quantity for such resources for each hour shall be the hourly integrated MW quantity to which the load reduction resource was dispatched for each hour (where the hourly integrated value is the average of the dispatched values as determined by the Office of the Interconnection for the resource for each hour).

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no balancing Operating Reserve deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the balancing Operating Reserve deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual reduction quantity). For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined in section 3.3A of this Appendix. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, 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, EKPC 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 except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, 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 that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM

Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. 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 resources 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 less the hourly integrated real-time LMP, with the exception of those hours in which the Non-Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone is not equal to zero. During such hours, Tier 1 Synchronized Reserve resources shall be compensated at the Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone for the lesser of the hourly integrated amount of Tier 1 Synchronized Reserve attributed to the resource as calculated by the Office of the Interconnection, or the actual amount of Tier 1 Synchronized Reserve provided should a Synchronized Reserve Event occur.

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 Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the operating day. The hourly Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of serving the next increment of demand for Synchronized Reserve in each Reserve Zone or Reserve Sub-zone, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve requirement in a Reserve Zone or Reserve Sub-zone cannot be met, the 5-minute clearing price shall be at least greater than or equal to the Synchronized Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the sum of the Synchronized Reserve Penalty Factor and the Primary Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the sum of the Primary Reserve Penalty Factor and the Synchronized Reserve Penalty Factor for that Reserve Zone or Reserve Sub-zone.

The Synchronized Reserve Penalty Factors shall each be phased in as described below:

- i. \$250/MWh for the 2012/2013 Delivery Year;
- ii. \$400/MWh for the 2013/2014 Delivery Year;
- iii. \$550/MWh for the 2014/2015 Delivery Year; and
- iv. \$850/MWh as of the 2015/2016 Delivery Year.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding \$1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Synchronized Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(e) In determining the 5-minute Synchronized Reserve 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 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 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 resource will be credited for Tier 2 Synchronized Reserve capacity in the amount that actually responded for the contiguous hours the resource was assigned Tier 2 Synchronized Reserve during which the event occurred, and 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 Reserve Zone and Reserve Sub-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.001 Non-Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-

Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. An Internal Market Buyer that does not meet its hourly Non-Synchronized Reserve Obligation shall be charged for the Non-Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Non-Synchronized Reserve Market Clearing Price determined in accordance with paragraph (c) of this section, plus the amounts, if any, described in paragraph (f) of this section.

(b) Credits for Non-Synchronized Reserve provided by generation resources that are not operating for energy at the direction of the Office of the Interconnection specifically for the purpose of providing Non-Synchronized Reserve shall be the higher of (i) the Non-Synchronized Reserve Market Clearing Price or (ii) the specific opportunity cost of the generation resource supplying the increment of Non-Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the operating day. The hourly Non-Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve requirement. When the Primary Reserve requirement in a Reserve Zone or Reserve Sub-zone cannot be met at a price less than or equal to the Primary Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve will be determined as the Primary Reserve Penalty Factor. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the Primary Reserve Penalty Factor for that Reserve Zone or Reserve Sub-zone.

The Primary Reserve Penalty Factors shall each be phased in as described below:

- i. \$250/MWh for the 2012/2013 Delivery Year;
- ii. \$400/MWh for the 2013/2014 Delivery Year;
- iii. \$550/MWh for the 2014/2015 Delivery Year; and
- iv. \$850/MWh as of the 2015/2016 Delivery Year.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding \$1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Primary Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(d) In determining the 5-minute Non-Synchronized Reserve clearing price, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves shall be equal to 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 Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Non-Synchronized Reserve and that 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 Non-Synchronized Reserve and shall be equal to 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 Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

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

(g) The magnitude of response to a Non-Synchronized Reserve Event by a generation resource is the difference between the generation resource's output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output at the start of the event is defined as the lowest telemetered generator resource output between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output 10 minutes after the start of the event is defined as the greatest generator resource output achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(h) In the event a generation resource that has been assigned by the Office of the Interconnection to provide Non-Synchronized Reserve fails to provide the assigned amount of Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the contiguous hours the resource was assigned Non-Synchronized Reserve during which the event occurred.

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 $\{(LMP_{DMW} - AG) \times (URTLMP - UB)\}$

where:

LMP_{DMW} 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, *and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output*;

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, *limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output*, if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the 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) $\{(URTLMP - UDALMP) \times DAG\}$, or (ii) $\{(URTLMP - UB) \times DAG\}$ 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 $\{(AG - LMPDMW) \times (UB - URTLMP)\}$ 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 subsection (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of the Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. 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) When the Office of the Interconnection has implemented Emergency procedures, resources offering Emergency energy are eligible to set real-time Locational Marginal Prices, capped at the energy offer cap plus the sum of the applicable Reserve Penalty Factors, provided that the Emergency energy is needed to meet demand in the PJM Region.

(b) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each 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.

(c) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each 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.

(d) 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.

5.2 Transmission Congestion Credit Calculation.

5.2.1 Eligibility.

(a) Except as provided in Section 5.2.1(b), each holder of a Financial Transmission Right shall receive as a Transmission Congestion Credit a proportional share of the total Transmission Congestion Charges collected for each constrained hour.

(b) If a holder of a Financial Transmission Right between specified delivery and receipt buses acquired the Financial Transmission Right in a Financial Transmission Rights auction (the procedures for which are set forth in Part 7 of this Schedule 1) and (i) had an Increment Bid and/or Decrement Bid that was accepted by the Office of the Interconnection for an applicable hour in the Day-ahead Energy Market for delivery or receipt at or near delivery or receipt buses of the Financial Transmission Right; and (ii) the result of the acceptance of such Increment Bid or Decrement Bid is that the difference in Locational Marginal Prices in the Day-ahead Energy Market between such delivery and receipt buses is greater than the difference in Locational Marginal Prices between such delivery and receipt buses in the Real-time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit, associated with such Financial Transmission Right in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount that the Market Participant paid for the Financial Transmission Right in the Financial Transmission Rights Auction.

(c) For purposes of Section 5.2.1(b) a bus shall be considered at or near the Financial Transmission Right delivery or receipt bus if seventy-five percent or more of the energy injected or withdrawn at that bus and which is withdrawn or injected at any other bus is reflected in the constrained path between the subject Financial Transmission Right delivery and receipt buses that were acquired in the Financial Transmission Rights auction.

(d) The Market Monitoring Unit shall calculate Transmission Congestion Credits pursuant to this section and section VI of Attachment M – Appendix. 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 agrees with such calculation, then it shall impose the forfeiture of the Transmission Congestion Credit accordingly. If the Office of the Interconnection does not agree with the calculation, then it shall impose a forfeiture of Transmission Congestion Credit consistent with its determination. If the Market Monitoring Unit disagrees with the Office of the Interconnection's determination, it may exercise its powers to inform the Commission staff of its concerns and may request an adjustment. This provision is duplicated in section VI of Attachment M – Appendix. An FTR holder objecting to the application of this rule shall have recourse to the Commission for review of the application of the FTR forfeiture rule to its trading activity.

5.2.2 Financial Transmission Rights.

(a) Transmission Congestion Credits will be calculated based upon the Financial Transmission Rights held at the time of the constrained hour. Except as provided in subsection (e) below, Financial Transmission Rights shall be auctioned as set forth in Section 7.

(b) The hourly economic value of a Financial Transmission Right Obligation is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right. The hourly economic value of a Financial Transmission Right Obligation is positive (a benefit to the Financial Transmission Right holder) when the Day-ahead Congestion Price at the point of delivery is higher than the Day-ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Obligation is negative (a liability to the holder) when the Day-ahead Congestion Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.

(c) The hourly economic value of a Financial Transmission Right Option is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right when that difference is positive. The hourly economic value of a Financial Transmission Right Option is positive (a benefit to the Financial Transmission Right holder) when the Day-ahead Congestion Price at the point of delivery is higher than the Day-ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Option is zero (neither a benefit nor a liability to the holder) when the Day-ahead Congestion Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.

(d) In addition to transactions with PJMSettlement in the Financial Transmission Rights auctions administered by the Office of the Interconnection, a Financial Transmission Right, for its entire tenure or for a specified monthly period, may be sold or otherwise transferred to a third party by bilateral agreement, subject to compliance with such procedures as may be established by the Office of the Interconnection for verification of the rights of the purchaser or transferee.

(i) Market Participants may enter into bilateral agreements to transfer to a third party a Financial Transmission Right, for its entire tenure or for a specified monthly period. Such bilateral transactions shall be reported to the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules related to its eFTR tools.

(ii) For purposes of clarity, with respect to all bilateral transactions for the transfer of Financial Transmission Rights, the rights and obligations pertaining to the Financial Transmission Rights that are the subject of such a bilateral transaction shall pass to the buyer under the bilateral contract subject to the provisions of this Schedule. Such bilateral transactions shall not modify the location or reconfigure the Financial Transmission Rights. In no event shall the purchase and sale of a Financial Transmission Right pursuant to a bilateral transaction constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.

(iii) Consent of the Office of the Interconnection shall be required for a seller to transfer to a buyer any Financial Transmission Right Obligation. Such consent shall be based

upon the Office of the Interconnection's assessment of the buyer's ability to perform the obligations, including meeting applicable creditworthiness requirements, transferred in the bilateral contract. If consent for a transfer is not provided by the Office of the Interconnection, the title to the Financial Transmission Rights shall not transfer to the third party and the holder of the Financial Transmission Rights shall continue to receive all Transmission Congestion Credits attributable to the Financial Transmission Rights and remain subject to all credit requirements and obligations associated with the Financial Transmission Rights.

(iv) A seller under such a bilateral contract shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any charges associated with the transferred Financial Transmission Right and for which payment is not made to PJMSettlement by the buyer under such a bilateral transaction.

(v) All payments and related charges associated with such a bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by PJMSettlement or the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral contract reported to the Office of the Interconnection under this Schedule.

(vi) All claims regarding a default of a buyer to a seller under such a bilateral contract shall be resolved solely between the buyer and the seller.

(e) Network Service Users and Firm Transmission Customers that take service that sinks, sources in, or is transmitted through new PJM zones, at their election, may receive a direct allocation of Financial Transmission Rights instead of an allocation of Auction Revenue Rights. Network Service Users and Firm Transmission Customers may make this election for the succeeding two annual FTR auctions after the integration of the new zone into the PJM interchange energy market. Such election shall be made prior to the commencement of each annual FTR auction. For purposes of this election, the Allegheny Power Zone shall be considered a new zone with respect to the annual Financial Transmission Right auction in 2003 and 2004. Network Service Users and Firm Transmission Customers in new PJM zones that elect not to receive direct allocations of Financial Transmission Rights shall receive allocations of Auction Revenue Rights. During the annual allocation process, the Financial Transmission Right allocation for new PJM zones shall be performed simultaneously with the Auction Revenue Rights allocations in existing and new PJM zones. Prior to the effective date of the initial allocation of FTRs in a new PJM Zone, PJM shall file with FERC, under section 205 of the Federal Power Act, the FTRs and ARRs allocated in accordance with sections 5 and 7 of this Schedule 1.

(f) For Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through new PJM zones that elect to receive direct allocations of Financial Transmission Rights, Financial Transmission Rights shall be allocated using the same allocation methodology as specified for the allocation of Auction Revenue Rights in Section 7.4.2 and in accordance with the following:

(i) Subject to subsection (ii) of this section, all Financial Transmission Rights must be simultaneously feasible. If all Financial Transmission Right requests made when Financial Transmission Rights are allocated for the new zone are not feasible then Financial Transmission Rights are prorated and allocated in proportion to the MW level requested and in inverse proportion to the effect on the binding constraints.

(ii) If any Financial Transmission Right requests that are equal to or less than a Network Service User's Zonal Base Load for the Zone or fifty percent of its transmission responsibility for Non-Zone Network Load, or fifty percent of megawatts of firm service between the receipt and delivery points of Firm Transmission Customers, are not feasible in the annual allocation and auction processes due to system conditions, then PJM shall increase the capability limits of the binding constraints that would have rendered the Financial Transmission Rights infeasible to the extent necessary in order to allocate such Financial Transmission Rights without their being infeasible for all rounds of the annual allocation and auction processes, provided that this subsection (ii) shall not apply if the infeasibility is caused by extraordinary circumstances. Additionally, such increased limits shall be included in subsequent modeling during the Planning Year to support any incremental allocations of Auction Revenue Rights and monthly and balance of the Planning Period Financial Transmission Rights auctions; unless and to the extent those system conditions that contributed to infeasibility in the annual process are not extant for the time period subject to the subsequent modeling, such as would be the case, for example, if transmission facilities are returned to service during the Planning Year. In these cases, any increase in the capability limits taken under this subsection (ii) during the annual process will be removed from subsequent modeling to support any incremental allocations of Auction Revenue Rights and monthly and balance of the Planning Period Financial Transmission Rights auctions.

For the purposes of this subsection (ii), extraordinary circumstances shall mean an event of force majeure that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Financial Transmission Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule 1 of this Agreement. If PJM allocates Financial Transmission Rights as a result of this subsection (ii) that would not otherwise have been feasible, then PJM shall notify Members and post on its web site (a) the aggregate megawatt quantities, by sources and sinks, of such Financial Transmission Rights and (b) any increases in capability limits used to allocate such Financial Transmission Rights.

(iii) In the event that Network Load changes from one Network Service User to another after an initial or annual allocation of Financial Transmission Rights in a new zone, Financial Transmission Rights will be reassigned on a proportional basis from the Network Service User losing the load to the Network Service User that is gaining the Network Load.

(g) At least one month prior to the integration of a new zone into the PJM Interchange Energy Market, Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through the new zone, shall receive an initial allocation of Financial Transmission Rights that will be in effect from the date of the integration

of the new zone until the next annual allocation of Financial Transmission Rights and Auction Revenue Rights. Such allocation of Financial Transmission Rights shall be made in accordance with Section 5.2.2(f) of this Schedule.

(h) The following congestion charge crediting and uplift (hereinafter, “mitigation”) rules shall apply to each new zone first integrated on any date from May 1, 2004 through May 31, 2005 for which FERC orders such mitigation as a result of a filing for such zone of the type specified in subsection (g) above. Where FERC orders such mitigation, such rules shall remain in effect for such zone from the date of its integration through May 31, 2005. All such mitigation shall terminate for all such zones on May 31, 2005.

1.) Mitigation shall apply only to Long-Term Firm Point-to-Point Transmission Service customers in such a zone that did not receive an allocation of ARRs or FTRs, as applicable, equal to the ARRs or FTRs such customer requested in the allocation for such zone. Only pro-rated requests that complied with the source, sink, and service level limitations stated in section 7.4.2(f) are eligible for mitigation. Such mitigation shall continue for the period stated above if a customer eligible for mitigation renews or rolls over its service agreement, but shall no longer apply if such a customer redirects its service to alternate points on a firm basis.

2.) The affected customers that will receive mitigation will be notified by PJM of the MW amount of mitigation they will receive based on the difference between the amount of ARRs or FTRs requested and the amount of ARRs or FTRs awarded.

3.) Mitigation provided herein applies only to requests submitted and pro-rated in the interim or annual ARR/FTR allocation process conducted for such zones for the time period specified above.

4.) For each affected customer as described above, PJM each month will provide a mitigation credit to offset any congestion charges incurred by such customer in connection with the MW amount for the contract reservation eligible for mitigation as determined under subsection (2) above. In no event shall the amount of any such credit exceed the net amount of any congestion paid (after taking account of any congestion credits) by such customer during such month with respect to such identified MW amount.

5.) The total cost of all such credits for all mitigated customers in a zone each month shall be charged to and collected from all Network Integration Transmission Service and Long-Term Firm Point-to-Point Transmission Service customers within such zone that received ARRs or FTRs or that received mitigation under this subsection (h), in proportion to each such customer’s share of the total allocated ARR/FTR MWs (including mitigation MWs). Mitigation and uplift shall be determined separately for each such zone.

5.2.3 Target Allocation of Transmission Congestion Credits.

A Target Allocation of Transmission Congestion Credits for each entity holding a Financial Transmission Right shall be determined for each Financial Transmission Right. Each Financial

Transmission Right shall be multiplied by the Day-ahead Congestion Price differences for the receipt and delivery points associated with the Financial Transmission Right, calculated as the Day-ahead Congestion Price at the delivery point(s) minus the Day-ahead Congestion Price at the receipt point(s). For the purposes of calculating Transmission Congestion Credits, the Day-ahead Congestion Price of a Zone is calculated as the sum of the Day-ahead Congestion Price of each bus that comprises the Zone multiplied by the percent of annual peak load assigned to each node in the Zone. Commencing with the 2015/2016 Planning Period, for the purposes of calculating Transmission Congestion Credits, the Day-ahead Congestion Price of a Residual Metered Load aggregate is calculated as the sum of the Day-ahead Congestion Price of each bus that comprises the Residual Metered Load aggregate multiplied by the percent of the annual peak residual load assigned to each bus that comprises the Residual Metered Load aggregate. When the FTR Target Allocation is positive, the FTR Target Allocation is a credit to the FTR holder. When the FTR Target Allocation is negative, the FTR Target Allocation is a debit to the FTR holder if the FTR is a Financial Transmission Right Obligation. When the FTR Target Allocation is negative, the FTR Target Allocation is set to zero if the FTR is a Financial Transmission Right Option. The total Target Allocation for Network Service Users and Transmission Customers for each hour shall be the sum of the Target Allocations associated with all of the Network Service Users' or Transmission Customers' Financial Transmission Rights.

5.2.4 [Reserved.]

5.2.5 Calculation of Transmission Congestion Credits.

(a) The total of all the **positive** Target Allocations determined as specified above shall be compared to the total Transmission Congestion Charges in each hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market. If the total of the Target Allocations is less than the total of the Transmission Congestion Charges, the Transmission Congestion Credit for each entity holding an FTR shall be equal to its Target Allocation. All remaining Transmission Congestion Charges shall be distributed as described below in Section 5.2.6 "Distribution of Excess Congestion Charges."

(b) If the total of the Target Allocations is greater than the total Transmission Congestion Charges for the hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market, each holder of Financial Transmission Rights shall be assigned a share of the total Transmission Congestion Charges in proportion to its Target Allocations for Financial Transmission Rights which have a positive Target Allocation value. Financial Transmission Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Transmission Congestion Credit.

(c) At the end of a Planning Period if all FTR holders did not receive Transmission Congestion Credits equal to their Target Allocations, the Office of the Interconnection shall assess a charge equal to the difference between the Transmission Congestion Credit Target Allocations for all revenue deficient FTRs and the actual Transmission Congestion Credits allocated to those FTR holders. A charge assessed pursuant to this section shall also include any aggregate charge assessed pursuant to section 7.4.4(c) of Schedule 1 of this Agreement and shall be allocated to all FTR holders on a pro-rata basis according to the total Target Allocations for

all FTRs held at any time during the relevant Planning Period. The charge shall be calculated and allocated in accordance with the following methodology:

1. The Office of the Interconnection shall calculate the total amount of uplift required as {[sum of the total monthly deficiencies in FTR Target Allocations for the Planning Period + the sum of the ARR Target Allocation deficiencies determined pursuant to section 7.4.4(c) of Schedule 1 of this Agreement] – [sum of the total monthly excess ARR revenues and congestion charges for the Planning Period]}.

2. For each Market Participant that held an FTR during the Planning Period, the Office of the Interconnection shall calculate the total Target Allocation associated with all FTRs held by the Market Participant during the Planning Period provided that, the foregoing notwithstanding, if the total Target Allocation for an individual Market Participant calculated pursuant to this section is negative the Office of Interconnection shall set the value to zero.

3. The Office of the Interconnection shall then allocate an uplift charge to each Market Participant that held an FTR at any time during the Planning Period in accordance with the following formula: {[total uplift] * [total Target Allocation for all FTRs held by the Market Participant at any time during the Planning Period] / [total Target Allocations for all FTRs held by all PJM Market Participants at any time during the Planning Period]}.

5.2.6 Distribution of Excess Congestion Charges.

(a) Excess Transmission Congestion Charges accumulated in a month shall be distributed to each holder of Financial Transmission Rights in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the holder during that month as compared to its total Target Allocations for the month.

(b) After the excess Transmission Congestion Charge distribution described in Section 5.2.6(a) is performed, any excess Transmission Congestion Charges remaining at the end of a month shall be distributed to each holder of Financial Transmission Rights in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the holder during the current Planning Period, including previously distributed excess Transmission Congestion Charges, as compared to its total Target Allocation for the Planning Period.

(c) Any excess Transmission Congestion Charges remaining at the end of a Planning Period shall be distributed to each holder of Auction Revenue Rights in proportion to, but not more than, any Auction Revenue Right deficiencies for that Planning Period.

(d) Any excess Transmission Congestion Charges remaining after a distribution pursuant to subsection (c) of this section shall be distributed to all FTR holders on a pro-rata basis according to the total Target Allocations for all FTRs held at any time during the relevant Planning Period. Any allocation pursuant to this subsection (d) shall be conducted in accordance with the following methodology:

1. For each Market Participant that held an FTR during the Planning Period, the Office of the Interconnection shall calculate the total Target Allocation associated with all FTRs held by the Market Participant during the Planning Period, provided that, the foregoing notwithstanding, if the total Target Allocation for an individual Market Participant calculated pursuant to this section is negative the Office of the Interconnection shall set the value to zero.

2. The Office of the Interconnection shall then allocate an excess Transmission Congestion Charge credit to each Market Participant that held an FTR at any time during the Planning Period in accordance with the following formula: $\{[\text{total excess Transmission Congestion Charges remaining after distributions pursuant to subsection (a)-(c) of this section}] * [\text{total Target Allocation for all FTRs held by the Market Participant at any time during the Planning Period}] / [\text{total Target Allocations for all FTRs held by all PJM Market Participants at any time during the Planning Period}]\}$.

Section(s) of the
PJM Operating Agreement
(Marked / Redline Format)

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 Internal 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 the following for Regulation dispatched by the Office of the Interconnection to meet such obligation: (i) the capability Regulation market-clearing price determined in accordance with subsection (h) of this section; (ii) the amounts, if any, described in subsection (f) of this section; and (iii) the performance Regulation market-clearing price determined in accordance with subsection (g) of this section.

(b) Each Market Seller and Generating Market Buyer shall be credited for each of its resources supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection such that the calculated credit for each increment of Regulation provided by each resource shall be the higher of: (i) the Regulation market-clearing price; or (ii) the sum of the applicable Regulation offers for a resource determined pursuant to Section 3.2.2A.1 of this Schedule, the unit-specific shoulder hour opportunity costs described in subsection (e) of this section, the unit-specific inter-temporal opportunity costs, and the unit-specific opportunity costs discussed in subsection (d) of this section.

(c) The total 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. In accordance with the PJM Manuals, the total Regulation market-clearing price shall be calculated by optimizing the dispatch profile to obtain the lowest cost combination set of resources that satisfies the Regulation requirement. The market-clearing price for each regulating hour shall be equal to the average of all 5-minute clearing prices calculated during that hour. The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource 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 3.2.2A.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 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, 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.

For hydroelectric resources offering to sell Regulation in a regulating hour, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the full value of the Locational Marginal Price at that generation bus for each megawatt of Regulation capability.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the expected Locational Marginal Price at the generation bus for the hydroelectric resource and the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. Estimated opportunity costs shall be zero for hydroelectric resources for which the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those hours during which all available units at the hydroelectric resource were operating is higher than the actual Locational Marginal Price at the generator bus for the regulating hour.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating and the expected Locational Marginal Price at the generation bus for the hydroelectric resource. Estimated opportunity costs shall be zero for hydroelectric resources for which the actual Locational Marginal Price at the generator bus for the regulating hour is higher than the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those hours during which all available units at the hydroelectric resource were operating.

For the purpose of committing resources and setting Regulation market clearing prices, the Office of the Interconnection shall utilize day-ahead Locational Marginal Prices to calculate opportunity costs for hydroelectric resources. For the purposes of settlements, the Office of the Interconnection shall utilize the real-time Locational Marginal Prices to calculate opportunity costs for hydroelectric resources.

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

(e) In determining the credit under subsection (b) to a Market Seller or 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.

(g) To determine the performance Regulation market-clearing price for each Regulation Zone, the Office of the Interconnection shall adjust the submitted performance offer for each resource in accordance with the historical performance of that resource, the amount of Regulation that resource will be dispatched based on the ratio of control signals calculated by the Office of the Interconnection, and the unit-specific benefits factor described in subsection (j) of this section for which that resource is qualified. The maximum adjusted performance offer of all cleared resources will set the performance Regulation market-clearing price.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions, will be credited for Regulation performance *by multiplying the assigned MW(s) by the performance Regulation market-clearing price, by the ratio between the requested mileage for the Regulation dispatch signal assigned to the Regulation resource and the Regulation dispatch signal assigned to traditional resources, and by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.*

(h) The Office of the Interconnection shall divide each Regulation resource's capability offer by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score for the resource for the purposes of committing resources and setting the market clearing prices.

The Office of the Interconnection shall calculate the capability Regulation market-clearing price for each Regulation Zone by subtracting the performance Regulation market-clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the capability Regulation market clearing price for that market hour.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions will be credited for Regulation capability based on the assigned MW and the capability Regulation market-clearing price multiplied by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(i) In accordance with the processes described in the PJM Manuals, the Office of the Interconnection shall: (i) calculate inter-temporal opportunity costs for each applicable resource; (ii) include such inter-temporal opportunity costs in each applicable resource's offer to sell frequency Regulation service; and (iii) account for such inter-temporal opportunity costs in the Regulation market-clearing price.

(j) The Office of the Interconnection shall calculate a unit-specific benefits factor for each of the dynamic Regulation signal and traditional Regulation signal in accordance with the PJM Manuals. Each resource shall be assigned a unit-specific benefits factor based on their order in the merit order stack for the applicable Regulation signal. The unit-specific benefits factor is the point on the benefits factor curve that aligns with the last megawatt, adjusted by historical performance, that resource will add to the dynamic resource stack. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

(k) The Office of the Interconnection shall calculate each Regulation resource's accuracy score. The accuracy score shall be the average of a delay score, correlation score, and energy score for each ten second interval. For purposes of setting the interval to be used for the correlation score and delay scores, PJM will use the maximum of the correlation score plus the delay score for each interval.

The Office of the Interconnection shall calculate the correlation score using the following statistical correlation function (r) that measures the delay in response between the Regulation signal and the resource change in output:

$$\text{Correlation Score} = r_{\text{Signal,Response}(\delta, \delta+5 \text{ Min})}; \\ \delta=0 \text{ to } 5 \text{ Min}$$

where δ is delay.

The Office of the Interconnection shall calculate the delay score using the following equation:

$$\text{Delay Score} = \text{Abs} ((\delta - 5 \text{ Minutes}) / (5 \text{ Minutes})).$$

The Office of the Interconnection shall calculate a energy score as a function of the difference in the energy provided versus the energy requested by the Regulation signal while scaling for the number of samples. The energy score is the absolute error (ϵ) as a function of the resource's Regulation capacity using the following equations:

$$\text{Energy Score} = 1 - 1/n \sum \text{Abs} (\text{Error});$$

$$\text{Error} = \text{Average of Abs} ((\text{Response} - \text{Regulation Signal}) / (\text{Hourly Average Regulation Signal})); \text{ and}$$

n = the number of samples in the hour and the energy.

The Office of the Interconnection shall calculate an accuracy score for each Regulation resource that is the average of the delay score, correlation score, and energy score for a five-minute period using the following equation where *the energy score, the delay score, and the correlation score are each weighted equally*:

$$\text{Accuracy Score} = \max ((\text{Delay Score}) + (\text{Correlation Score})) + (\text{Energy Score}).$$

The historic accuracy score will be based on a rolling average of the hourly accuracy scores, with consideration of the qualification score, as defined in the PJM Manuals.

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 *multiplied* by the historic accuracy score of the resource and multiplied by the unit-specific benefits factor for which the capability cost-based offer plus the performance 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.
- (iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the

Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

(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. PJM shall also (i) determine whether any resources were scheduled in the Day-ahead Energy Market to provide Black Start service, Reactive Services or transfer interface control during the Operating Day because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day in order to minimize the total cost of Operating Reserves associated with the provision of such services and reflect the most accurate possible expectation of real-time operating conditions in the day-ahead model, which resources would not have otherwise been committed in the day-ahead security-constrained dispatch and (ii) report on the day following the Operating Day the megawatt quantities scheduled in the Day-ahead Energy Market for the above-enumerated purposes for the entire RTO.

Except as provided in Section 3.2.3(n), 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, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load (net of operating Behind The Meter Generation) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

(e) 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 in as determined by the Real-time Day-ahead Energy Market plus any credit or change for quantity deviations, at PJM dispatch direction, from the Day-ahead Energy Market during the Operating Day ~~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), 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 Non-Synchronized Reserve in excess of the Non-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, Non-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, Non-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 $\{(LMP_{DMW} - AG) \times (URTLMP - UB)\}$, where:

LMP_{DMW} 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 *and limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output*;

AG equals the actual hourly integrated output of the unit;

URLTMP 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 $URLTMP - UB$ 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, *and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output*, if either of the following conditions occur:

- (i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described 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) $\{(URLTMP - UDALMP) \times DAG\}$, or (ii) $\{(URLTMP - UB) \times DAG\}$ where:

URLTMP 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.

(f-4) A Market Seller's wind generating unit that is pool-scheduled or self-scheduled and operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the 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 $\{(LMPDMW - AG) \times (URTLMP - UB)\}$, where:

LMPDMW equals the lesser of the PJM forecasted output for the unit or 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, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;

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.

In the event the Office of the Interconnection experiences a technical problem or malfunction with its wind forecasting tool that results in an erroneous forecast for a wind resource during a period of time for which the wind resource is eligible for lost opportunity cost, the Office of the Interconnection and the Market Seller will attempt to reach a mutually agreeable forecast value for settlement purposes. If the Office of the Interconnection and the Market Seller do not come to mutual agreement on an acceptable forecast value, the Office of the Interconnection shall utilize the forecast value that it determines is appropriate.

(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, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (1) 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 in subsection (h)(ii) below and in the PJM Manuals; (2) 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; (3) 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 (4) 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.

The costs associated with scheduling of units for Black Start service or testing of Black Start Units shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff.

Notwithstanding section (h)(1) above, as more fully set forth in the PJM Manuals, load deviations from the Day-ahead Energy Market shall not be assessed Operating Reserves charges to the extent attributable to reductions in the load of Price Responsive Demand that is in response to an increase in Locational Marginal Price from the Day-ahead Energy Market to the Real-time Energy Market and that is in accordance with a properly submitted PRD Curve.

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 buses 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 buses 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.
 - (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 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 generation resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:

- (i) real-time economic minimum $\leq$ 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.
- (ii) real-time economic maximum $\geq$ 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:

$$\text{Ramp_Request}_t = \frac{(\text{UDStarget}_{t-1} - \text{AOutput}_{t-1})}{(\text{UDSLatime}_{t-1})}$$

$$\text{RL_Desired}_t = \text{AOutput}_{t-1} + \left(\text{Ramp_Request}_t * \text{Case_Eff_time}_{t-1} \right)$$

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 generation resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the 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 $\leq$ 10, or its 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 $\leq 20\%$, 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.

(o-1) Dispatchable economic load reduction resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Economic load reduction resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations as described in this subsection and as further specified in the PJM Manuals.

The Desired MW quantity for such resources for each hour shall be the hourly integrated MW quantity to which the load reduction resource was dispatched for each hour (where the hourly integrated value is the average of the dispatched values as determined by the Office of the Interconnection for the resource for each hour).

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no balancing Operating Reserve deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the balancing Operating Reserve deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual

reduction quantity). For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined in section 3.3A of this Appendix. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, 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, *EKPC* 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 except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, 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 that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. 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 resources 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 less the hourly integrated real-time LMP, with the exception of those hours in which the Non-Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone is not equal to zero. During such hours, Tier 1 Synchronized Reserve resources shall be compensated at the Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone for the lesser of the hourly integrated amount of Tier 1 Synchronized Reserve attributed to the resource as calculated by the Office of the Interconnection, or the actual amount of Tier 1 Synchronized Reserve provided should a Synchronized Reserve Event occur.

- 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 Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the operating day. The hourly Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of serving the next increment of demand for Synchronized Reserve in each Reserve Zone or Reserve Sub-zone, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve requirement in a Reserve Zone or Reserve Sub-zone cannot be met, the 5-minute clearing price shall be at least greater than or equal to the Synchronized Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the sum of the Synchronized Reserve Penalty Factor and the Primary Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the sum of the Primary Reserve Penalty Factor and the Synchronized Reserve Penalty Factor for that Reserve Zone or Reserve Sub-zone.

The Synchronized Reserve Penalty Factors shall each be phased in as described below:

- i. \$250/MWh for the 2012/2013 Delivery Year;

- ii. \$400/MWh for the 2013/2014 Delivery Year;
- iii. \$550/MWh for the 2014/2015 Delivery Year; and
- iv. \$850/MWh as of the 2015/2016 Delivery Year.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding \$1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Synchronized Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(e) In determining the 5-minute Synchronized Reserve 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 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 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 resource will be credited for Tier 2 Synchronized Reserve capacity in the amount that actually responded for the contiguous hours the resource was assigned Tier 2 Synchronized Reserve during which the event occurred, and 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 Reserve Zone and Reserve Sub-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.001 Non-Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. An Internal Market Buyer that does not meet its hourly Non-Synchronized Reserve Obligation shall be charged for the Non-Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Non-Synchronized Reserve Market Clearing Price determined in accordance with paragraph (c) of this section, plus the amounts, if any, described in paragraph (f) of this section.

(b) Credits for Non-Synchronized Reserve provided by generation resources that are not operating for energy at the direction of the Office of the Interconnection specifically for the purpose of providing Non-Synchronized Reserve shall be the higher of (i) the Non-Synchronized Reserve Market Clearing Price or (ii) the specific opportunity cost of the generation resource supplying the increment of Non-Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the operating day. The hourly Non-Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve requirement. When the Primary Reserve requirement in a Reserve Zone or Reserve Sub-zone cannot be met at a price less than or equal to the Primary Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve will be determined as the Primary Reserve Penalty Factor. If the

Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the Primary Reserve Penalty Factor for that Reserve Zone or Reserve Sub-zone.

The Primary Reserve Penalty Factors shall each be phased in as described below:

- i. \$250/MWh for the 2012/2013 Delivery Year;
- ii. \$400/MWh for the 2013/2014 Delivery Year;
- iii. \$550/MWh for the 2014/2015 Delivery Year; and
- iv. \$850/MWh as of the 2015/2016 Delivery Year.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding \$1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Primary Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(d) In determining the 5-minute Non-Synchronized Reserve clearing price, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves shall be equal to 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 Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Non-Synchronized Reserve and that 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 Non-Synchronized Reserve and shall be equal to 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 Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

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

(g) The magnitude of response to a Non-Synchronized Reserve Event by a generation resource is the difference between the generation resource's output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output at the start of the event is defined as the

lowest telemetered generator resource output between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output 10 minutes after the start of the event is defined as the greatest generator resource output achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(h) In the event a generation resource that has been assigned by the Office of the Interconnection to provide Non-Synchronized Reserve fails to provide the assigned amount of Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the contiguous hours the resource was assigned Non-Synchronized Reserve during which the event occurred.

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 $\{(LMP_{DMW} - AG) \times (URTLMP - UB)\}$

where:

LMP_{DMW} 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, *and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output*;

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, *limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output*, if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the 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) $\{(URTLMP - UDALMP) \times DAG\}$, or (ii) $\{(URTLMP - UB) \times DAG\}$ 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 $\{(AG - LMP_{DMW}) \times (UB - URTLMP)\}$ where:

AG equals the actual hourly integrated output of the unit;

LMP_{DMW} 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;

URLTMP 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 subsection (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of the Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. 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) When the Office of the Interconnection has implemented Emergency procedures, resources offering Emergency energy are eligible to set real-time Locational Marginal Prices, capped at the energy offer cap plus the sum of the applicable Reserve Penalty Factors, provided that the Emergency energy is needed to meet demand in the PJM Region.

(b) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each 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.

(c) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each 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.

(d) 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.

5.2 Transmission Congestion Credit Calculation.

5.2.1 Eligibility.

(a) Except as provided in Section 5.2.1(b), each holder of a Financial Transmission Right shall receive as a Transmission Congestion Credit a proportional share of the total Transmission Congestion Charges collected for each constrained hour.

(b) If a holder of a Financial Transmission Right between specified delivery and receipt buses acquired the Financial Transmission Right in a Financial Transmission Rights auction (the procedures for which are set forth in Part 7 of this Schedule 1) and (i) had an Increment Bid and/or Decrement Bid that was accepted by the Office of the Interconnection for an applicable hour in the Day-ahead Energy Market for delivery or receipt at or near delivery or receipt buses of the Financial Transmission Right; and (ii) the result of the acceptance of such Increment Bid or Decrement Bid is that the difference in Locational Marginal Prices in the Day-ahead Energy Market between such delivery and receipt buses is greater than the difference in Locational Marginal Prices between such delivery and receipt buses in the Real-time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit, associated with such Financial Transmission Right in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount that the Market Participant paid for the Financial Transmission Right in the Financial Transmission Rights auction.

(c) For purposes of Section 5.2.1(b) a bus shall be considered at or near the Financial Transmission Right delivery or receipt bus if seventy-five percent or more of the energy injected or withdrawn at that bus and which is withdrawn or injected at any other bus is reflected in the constrained path between the subject Financial Transmission Right delivery and receipt buses that were acquired in the Financial Transmission Rights auction.

(d) The Market Monitoring Unit shall calculate Transmission Congestion Credits pursuant to this section and section VI of Attachment M – Appendix. 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 agrees with such calculation, then it shall impose the forfeiture of the Transmission Congestion Credit accordingly. If the Office of the Interconnection does not agree with the calculation, then it shall impose a forfeiture of Transmission Congestion Credit consistent with its determination. If the Market Monitoring Unit disagrees with the Office of the Interconnection's determination, it may exercise its powers to inform the Commission staff of its concerns and may request an adjustment. This provision is duplicated in section VI of Attachment M – Appendix. An FTR holder objecting to the application of this rule shall have recourse to the Commission for review of the application of the FTR forfeiture rule to its trading activity.

5.2.2 Financial Transmission Rights.

- (a) Transmission Congestion Credits will be calculated based upon the Financial Transmission Rights held at the time of the constrained hour. Except as provided in subsection (e) below, Financial Transmission Rights shall be auctioned as set forth in Section 7.
- (b) The hourly economic value of a Financial Transmission Right Obligation is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right. The hourly economic value of a Financial Transmission Right Obligation is positive (a benefit to the Financial Transmission Right holder) when the Day-ahead Congestion Price at the point of delivery is higher than the Day-ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Obligation is negative (a liability to the holder) when the Day-ahead Congestion Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.
- (c) The hourly economic value of a Financial Transmission Right Option is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right when that difference is positive. The hourly economic value of a Financial Transmission Right Option is positive (a benefit to the Financial Transmission Right holder) when the Day-ahead Congestion Price at the point of delivery is higher than the Day-ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Option is zero (neither a benefit nor a liability to the holder) when the Day-ahead Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.
- (d) In addition to transactions with PJMSettlement in the Financial Transmission Rights auctions administered by the Office of the Interconnection, a Financial Transmission Right, for its entire tenure or for a specified monthly period, may be sold or otherwise transferred to a third party by bilateral agreement, subject to compliance with such procedures as may be established by the Office of the Interconnection for verification of the rights of the purchaser or transferee.
- (i) Market Participants may enter into bilateral agreements to transfer to a third party a Financial Transmission Right, for its entire tenure or for a specified monthly period. Such bilateral transactions shall be reported to the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules related to its eFTR tools.
 - (ii) For purposes of clarity, with respect to all bilateral transactions for the transfer of Financial Transmission Rights, the rights and obligations pertaining to the Financial Transmission Rights that are the subject of such a bilateral transaction shall pass to the buyer under the bilateral contract subject to the provisions of this Schedule. Such bilateral transactions shall not modify the location or reconfigure the Financial Transmission Rights. In no event shall the purchase and sale of a Financial Transmission Right pursuant to a bilateral transaction constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.

- (iii) Consent of the Office of the Interconnection shall be required for a seller to transfer to a buyer any Financial Transmission Right Obligation. Such consent shall be based upon the Office of the Interconnection's assessment of the buyer's ability to perform the obligations, including meeting applicable creditworthiness requirements, transferred in the bilateral contract. If consent for a transfer is not provided by the Office of the Interconnection, the title to the Financial Transmission Rights shall not transfer to the third party and the holder of the Financial Transmission Rights shall continue to receive all Transmission Congestion Credits attributable to the Financial Transmission Rights and remain subject to all credit requirements and obligations associated with the Financial Transmission Rights.
 - (iv) A seller under such a bilateral contract shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any charges associated with the transferred Financial Transmission Right and for which payment is not made to PJMSettlement by the buyer under such a bilateral transaction.
 - (v) All payments and related charges associated with such a bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by PJMSettlement or the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral contract reported to the Office of the Interconnection under this Schedule.
 - (vi) All claims regarding a default of a buyer to a seller under such a bilateral contract shall be resolved solely between the buyer and the seller.
- (e) Network Service Users and Firm Transmission Customers that take service that sinks, sources in, or is transmitted through new PJM zones, at their election, may receive a direct allocation of Financial Transmission Rights instead of an allocation of Auction Revenue Rights. Network Service Users and Firm Transmission Customers may make this election for the succeeding two annual FTR auctions after the integration of the new zone into the PJM Interchange Energy Market. Such election shall be made prior to the commencement of each annual FTR auction. For purposes of this election, the Allegheny Power Zone shall be considered a new zone with respect to the annual Financial Transmission Right auction in 2003 and 2004. Network Service Users and Firm Transmission Customers in new PJM zones that elect not to receive direct allocations of Financial Transmission Rights shall receive allocations of Auction Revenue Rights. During the annual allocation process, the Financial Transmission Right allocation for new PJM zones shall be performed simultaneously with the Auction Revenue Rights allocations in existing and new PJM zones. Prior to the effective date of the initial allocation of FTRs in a new PJM Zone, PJM shall file with FERC, under section 205 of the Federal Power Act, the FTRs and ARRs allocated in accordance with sections 5 and 7 of this Schedule 1.

(f) For Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through new PJM zones, that elect to receive direct allocations of Financial Transmission Rights, Financial Transmission Rights shall be allocated using the same allocation methodology as is specified for the allocation of Auction Revenue Rights in Section 7.4.2 and in accordance with the following:

- (i) Subject to subsection (ii) of this section, all Financial Transmission Rights must be simultaneously feasible. If all Financial Transmission Right requests made when Financial Transmission Rights are allocated for the new zone are not feasible then Financial Transmission Rights are prorated and allocated in proportion to the MW level requested and in inverse proportion to the effect on the binding constraints.
- (ii) If any Financial Transmission Right requests that are equal to or less than a Network Service User's Zonal Base Load for the Zone or fifty percent of its transmission responsibility for Non-Zone Network Load, or fifty percent of megawatts of firm service between the receipt and delivery points of Firm Transmission Customers, are not feasible in the annual allocation and auction processes due to system conditions, then PJM shall increase the capability limits of the binding constraints that would have rendered the Financial Transmission Rights infeasible to the extent necessary in order to allocate such Financial Transmission Rights without their being infeasible for all rounds of the annual allocation and auction processes, provided that this subsection (ii) shall not apply if the infeasibility is caused by extraordinary circumstances. Additionally, such increased limits shall be included in subsequent modeling during the Planning Year to support any incremental allocations of Auction Revenue Rights and monthly and balance of the Planning Period Financial Transmission Rights auctions; unless and to the extent those system conditions that contributed to infeasibility in the annual process are not extant for the time period subject to the subsequent modeling, such as would be the case, for example, if transmission facilities are returned to service during the Planning Year. In these cases, any increase in the capability limits taken under this subsection (ii) during the annual process will be removed from subsequent modeling to support any incremental allocations of Auction Revenue Rights and monthly and balance of the Planning Period Financial Transmission Rights auctions.

For the purposes of this subsection (ii), extraordinary circumstances shall mean an event of force majeure that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Financial Transmission Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule 1 of this Agreement. If PJM allocates Financial Transmission Rights as a result of this subsection (ii) that would not otherwise have been feasible, then PJM shall notify Members and post on its web site (a) the aggregate megawatt quantities, by

sources and sinks, of such Financial Transmission Rights and (b) any increases in capability limits used to allocate such Financial Transmission Rights.

- (iii) In the event that Network Load changes from one Network Service User to another after an initial or annual allocation of Financial Transmission Rights in a new zone, Financial Transmission Rights will be reassigned on a proportional basis from the Network Service User losing the load to the Network Service User that is gaining the Network Load.

(g) At least one month prior to the integration of a new zone into the PJM Interchange Energy Market, Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through the new zone, shall receive an initial allocation of Financial Transmission Rights that will be in effect from the date of the integration of the new zone until the next annual allocation of Financial Transmission Rights and Auction Revenue Rights. Such allocation of Financial Transmission Rights shall be made in accordance with Section 5.2.2(f) of this Schedule.

(h) The following congestion charge crediting and uplift (hereinafter, "mitigation") rules shall apply to each new zone first integrated on any date from May 1, 2004 through May 31, 2005 for which FERC orders such mitigation as a result of a filing for such zone of the type specified in subsection (g) above. Where FERC orders such mitigation, such rules shall remain in effect for such zone from the date of its integration through May 31, 2005. All such mitigation shall terminate for all such zones on May 31, 2005.

- 1.) Mitigation shall apply only to Long-Term Firm Point-to-Point Transmission Service customers in such a zone that did not receive an allocation of ARRs or FTRs, as applicable, equal to the ARRs or FTRs such customer requested in the allocation for such zone. Only pro-rated requests that complied with the source, sink, and service level limitations stated in section 7.4.2(f) are eligible for mitigation. Such mitigation shall continue for the period stated above if a customer eligible for mitigation renews or rolls over its service agreement, but shall no longer apply if such a customer redirects its service to alternate points on a firm basis.
- 2.) The affected customers that will receive mitigation will be notified by PJM of the MW amount of mitigation they will receive based on the difference between the amount of ARRs or FTRs requested and the amount of ARRs or FTRs awarded.
- 3.) Mitigation provided herein applies only to requests submitted and pro-rated in the interim or annual ARR/FTR allocation process conducted for such zones for the time period specified above.
- 4.) For each affected customer as described above, PJM each month will provide a mitigation credit to offset any congestion charges incurred by such customer in connection with the MW amount for the contract reservation eligible for mitigation as determined under subsection (2) above. In no event shall the

amount of any such credit exceed the net amount of any congestion paid (after taking account of any congestion credits) by such customer during such month with respect to such identified MW amount.

- 5.) The total cost of all such credits for all mitigated customers in a zone each month shall be charged to and collected from all Network Integration Transmission Service and Long-Term Firm Point-to-Point Transmission Service customers within such zone that received ARRs or FTRs or that received mitigation under this subsection (h), in proportion to each such customer's share of the total allocated ARR/FTR MWs (including mitigation MWs). Mitigation and uplift shall be determined separately for each such zone.

5.2.3 Target Allocation of Transmission Congestion Credits.

A Target Allocation of Transmission Congestion Credits for each entity holding a Financial Transmission Right shall be determined for each Financial Transmission Right. Each Financial Transmission Right shall be multiplied by the Day-ahead Congestion Price differences for the receipt and delivery points associated with the Financial Transmission Right, calculated as the Day-ahead Congestion Price at the delivery point(s) minus the Day-ahead Congestion Price at the receipt point(s). For the purposes of calculating Transmission Congestion Credits, the Day-ahead Congestion Price of a Zone is calculated as the sum of the Day-ahead Congestion Price of each bus that comprises the Zone multiplied by the percent of annual peak load assigned to each node in the Zone. Commencing with the 2015/2016 Planning Period, for the purposes of calculating Transmission Congestion Credits, the Day-ahead Congestion Price of a Residual Metered Load aggregate is calculated as the sum of the Day-ahead Congestion Price of each bus that comprises the Residual Metered Load aggregate multiplied by the percent of the annual peak residual load assigned to each bus that comprises the Residual Metered Load aggregate. When the FTR Target Allocation is positive, the FTR Target Allocation is a credit to the FTR holder. When the FTR Target Allocation is negative, the FTR Target Allocation is a debit to the FTR holder if the FTR is a Financial Transmission Right Obligation. When the FTR Target Allocation is negative, the FTR Target Allocation is set to zero if the FTR is a Financial Transmission Right Option. The total Target Allocation for Network Service Users and Transmission Customers for each hour shall be the sum of the Target Allocations associated with all of the Network Service Users' or Transmission Customers' Financial Transmission Rights.

5.2.4 [Reserved.]

5.2.5 Calculation of Transmission Congestion Credits.

- (a) The total of all the positive Target Allocations determined as specified above shall be compared to the total Transmission Congestion Charges in each hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market. If the total of the Target Allocations is less than the total of the Transmission Congestion Charges, the Transmission Congestion Credit for each entity holding an FTR shall be equal to its Target Allocation. All remaining Transmission Congestion Charges shall be distributed as described below in Section 5.2.6 "Distribution of Excess Congestion Charges."

(b) If the total of the Target Allocations is greater than the total Transmission Congestion Charges for the hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market, each holder of Financial Transmission Rights shall be assigned a share of the total Transmission Congestion Charges in proportion to its Target Allocations for Financial Transmission Rights which have a positive Target Allocation value. Financial Transmission Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Transmission Congestion Credit.

(c) At the end of a Planning Period if all FTR holders did not receive Transmission Congestion Credits equal to their Target Allocations, the Office of the Interconnection shall assess a charge equal to the difference between the Transmission Congestion Credit Target Allocations for all revenue deficient FTRs and the actual Transmission Congestion Credits allocated to those FTR holders. A charge assessed pursuant to this section shall also include any aggregate charge assessed pursuant to section 7.4.4(c) of Schedule 1 of this Agreement and shall be allocated to all FTR holders on a pro-rata basis according to the total Target Allocations for all FTRs held at any time during the relevant Planning Period. The charge shall be calculated and allocated in accordance with the following methodology:

1. The Office of the Interconnection shall calculate the total amount of uplift required as $\{[\text{sum of the total monthly deficiencies in FTR Target Allocations for the Planning Period} + \text{the sum of the ARR Target Allocation deficiencies determined pursuant to section 7.4.4(c) of Schedule 1 of this Agreement}] - [\text{sum of the total monthly excess ARR revenues and congestion charges for the Planning Period}]\}$.
2. For each Market Participant that held an FTR during the Planning Period, the Office of the Interconnection shall calculate the total Target Allocation associated with all FTRs held by the Market Participant during the Planning Period, provided that, the foregoing notwithstanding, if the total Target Allocation for an individual Market Participant calculated pursuant to this section is negative the Office of Interconnection shall set the value to zero.
3. The Office of the Interconnection shall then allocate an uplift charge to each Market Participant that held an FTR at any time during the Planning Period in accordance with the following formula: $\{[\text{total uplift}] * [\text{total Target Allocation for all FTRs held by the Market Participant at any time during the Planning Period}] / [\text{total Target Allocations for all FTRs held by all PJM Market Participants at any time during the Planning Period}]\}$.

5.2.6 Distribution of Excess Congestion Charges.

(a) Excess Transmission Congestion Charges accumulated in a month shall be distributed to each holder of Financial Transmission Rights in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the holder during that month as compared to its total Target Allocations for the month.

(b) After the excess Transmission Congestion Charge distribution described in Section 5.2.6(a) is performed, any excess Transmission Congestion Charges remaining at the end of a month shall be distributed to each holder of Financial Transmission Rights in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the holder during the current Planning Period, including previously distributed excess Transmission Congestion Charges, as compared to its total Target Allocation for the Planning Period.

(c) Any excess Transmission Congestion Charges remaining at the end of a Planning Period shall be distributed to each holder of Auction Revenue Rights in proportion to, but not more than, any Auction Revenue Right deficiencies for that Planning Period.

(d) Any excess Transmission Congestion Charges remaining after a distribution pursuant to subsection (c) of this section shall be distributed to all FTR holders on a pro-rata basis according to the total Target Allocations for all FTRs held at any time during the relevant Planning Period. Any allocation pursuant to this subsection (d) shall be conducted in accordance with the following methodology:

1. For each Market Participant that held an FTR during the Planning Period, the Office of the Interconnection shall calculate the total Target Allocation associated with all FTRs held by the Market Participant during the Planning Period, provided that, the foregoing notwithstanding, if the total Target Allocation for an individual Market Participant calculated pursuant to this section is negative the Office of the Interconnection shall set the value to zero.
2. The Office of the Interconnection shall then allocate an excess Transmission Congestion Charge credit to each Market Participant that held an FTR at any time during the Planning Period in accordance with the following formula: $\{[\text{total excess Transmission Congestion Charges remaining after distributions pursuant to subsection (a)-(c) of this section}] * [\text{total Target Allocation for all FTRs held by the Market Participant at any time during the Planning Period}] / [\text{total Target Allocations for all FTRs held by all PJM Market Participants at any time during the Planning Period}]\}$.

Attachment B

Revisions to the PJM Open Access Transmission Tariff and PJM Operating Agreement

(Clean Format)

Section(s) of the
PJM Open Access Transmission Tariff
(Clean Format)

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 Black Start Service revenue requirements and 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, with a copy to the Office of the Interconnection, by no later than May 3 of each year. The Market Monitoring Unit and the Black Start Unit owner shall attempt to come to agreement on the level of each component included in the Black Start Service revenue requirements by no later than May 14 of each year. By no later than May 21 of each year, the Black Start Unit owner shall notify the Office of the Interconnection and the Market Monitoring Unit in writing whether it agrees or disagrees with the Market Monitoring Unit's determination of the level of each component included in the Black Start Service revenue requirements. The Black Start Unit owner may also submit Black Start Service revenue requirements that it chooses to the Office of the Interconnection by no later than May 21 of each year, 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 Unit 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 and PJM Manuals.

The Office of the Interconnection shall determine whether to accept the values submitted by the Black Start Unit owner subject to the requirements of the Tariff and the PJM Manuals by no later than May 27. If the Office of the Interconnection does not accept the values submitted by the Black Start Unit owner in such case, the Black Start Unit 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 Unit owner in such case, the Market Monitoring Unit may petition the Commission for an order that would require the Black Start Unit owner to utilize the values determined by the Market Monitoring Unit or the Office of the Interconnection or such other values as determined by the Commission. The annual calculation of Black Start Service revenue requirements shall become effective on June 1 of each year, except that 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. Notwithstanding the foregoing, the deadlines set forth in this section 17 shall not apply to a Black Start Unit owner's election to select a new method of recovery for its Fixed BSSC.

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

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

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

$$(\text{Training Costs}) * (1 + Z)$$

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:

$$\text{Net CONE} * \text{Black Start Unit Capacity} * X$$

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 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

$$(\text{Net Cone} * \text{Black Start NERC-CIP Unit Capacity} * X) + (\text{Incremental Black Start NERC-CIP Capital Costs} * \text{CRF})$$

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 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. To the extent that a Black Start Unit owner is currently recovering black start costs pursuant to a FERC-approved rate, that cost recovery will be included as a formulaic component for calculating the Black Start Unit’s annual revenue requirement pursuant to this paragraph 18. However, under no circumstances will PJM or the Black Start Unit owner restructure or modify that existing FERC-approved rate without FERC approval.

“Incremental Black Start Capital Costs” are the new or additional capital costs 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 Unit 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.

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:

$$\text{Black Start Unit O\&M} * Y$$

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:

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

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 traded the first business day on or following May 1.

“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 reported the first business day on or following May 1.

“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 shall be an incentive factor solely for Black Start Units with a commitment established under section 5 above and shall be ten percent. For those Black Start Units that elect to recover new or additional Black Start Capital Costs under section 6 above, the incentive factor, Z, shall be equal to zero.

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 criteria for Black Start Service and the criteria for Black Start Service in the Applicable Standards 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.

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 Internal 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 the following for Regulation dispatched by the Office of the Interconnection to meet such obligation: (i) the capability Regulation market-clearing price determined in accordance with subsection (h) of this section; (ii) the amounts, if any, described in subsection (f) of this section; and (iii) the performance Regulation market-clearing price determined in accordance with subsection (g) of this section.

(b) Each Market Seller and Generating Market Buyer shall be credited for each of its resources supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection such that the calculated credit for each increment of Regulation provided by each resource shall be the higher of: (i) the Regulation market-clearing price; or (ii) the sum of the applicable Regulation offers for a resource determined pursuant to Section 3.2.2A.1 of this Schedule, the unit-specific shoulder hour opportunity costs described in subsection (e) of this section, the unit-specific inter-temporal opportunity costs, and the unit-specific opportunity costs discussed in subsection (d) of this section.

(c) The total 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. In accordance with the PJM Manuals, the total Regulation market-clearing price shall be calculated by optimizing the dispatch profile to obtain the lowest cost combination set of resources that satisfies the Regulation requirement. The market-clearing price for each regulating hour shall be equal to the average of all 5-minute clearing prices calculated during that hour. The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource 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 3.2.2A.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 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, 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.

For hydroelectric resources offering to sell Regulation in a regulating hour, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the full value of the Locational Marginal Price at that generation bus for each megawatt of Regulation capability.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the expected Locational Marginal Price at the generation bus for the hydroelectric resource and the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. Estimated opportunity costs shall be zero for hydroelectric resources for which the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those hours during which all available units at the hydroelectric resource were operating is higher than the actual Locational Marginal Price at the generator bus for the regulating hour.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating and the expected Locational Marginal Price at the generation bus for the hydroelectric resource. Estimated opportunity costs shall be zero for hydroelectric resources for which the actual Locational Marginal Price at the generator bus for the regulating hour is higher than the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those hours during which all available units at the hydroelectric resource were operating.

For the purpose of committing resources and setting Regulation market clearing prices, the Office of the Interconnection shall utilize day-ahead Locational Marginal Prices to calculate opportunity costs for hydroelectric resources. For the purposes of settlements, the Office of the Interconnection shall utilize the real-time Locational Marginal Prices to calculate opportunity costs for hydroelectric resources.

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

(e) In determining the credit under subsection (b) to a Market Seller or 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.

(g) To determine the performance Regulation market-clearing price for each Regulation Zone, the Office of the Interconnection shall adjust the submitted performance offer for each resource in accordance with the historical performance of that resource, the amount of Regulation that resource will be dispatched based on the ratio of control signals calculated by the Office of the Interconnection, and the unit-specific benefits factor described in subsection (j) of this section for which that resource is qualified. The maximum adjusted performance offer of all cleared resources will set the performance Regulation market-clearing price.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions, will be credited for Regulation performance *by multiplying* the assigned MW(s) by the performance Regulation market-clearing price, *by the ratio between the requested mileage for the Regulation dispatch signal assigned to the Regulation resource and the Regulation dispatch signal assigned to traditional resources*, and *by the Regulation resource's accuracy score* calculated in accordance with subsection (k) of this section.

(h) The Office of the Interconnection shall divide each Regulation resource's capability offer by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score for the resource for the purposes of committing resources and setting the market clearing prices.

The Office of the Interconnection shall calculate the capability Regulation market-clearing price for each Regulation Zone by subtracting the performance Regulation market-clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the capability Regulation market clearing price for that market hour.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions will be credited for Regulation capability based on the assigned MW and the capability Regulation market-clearing price multiplied by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(i) In accordance with the processes described in the PJM Manuals, the Office of the Interconnection shall: (i) calculate inter-temporal opportunity costs for each applicable resource; (ii) include such inter-temporal opportunity costs in each applicable resource's offer to sell

frequency Regulation service; and (iii) account for such inter-temporal opportunity costs in the Regulation market-clearing price.

(j) The Office of the Interconnection shall calculate a unit-specific benefits factor for each of the dynamic Regulation signal and traditional Regulation signal in accordance with the PJM Manuals. Each resource shall be assigned a unit-specific benefits factor based on their order in the merit order stack for the applicable Regulation signal. The unit-specific benefits factor is the point on the benefits factor curve that aligns with the last megawatt, adjusted by historical performance, that resource will add to the dynamic resource stack. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

(k) The Office of the Interconnection shall calculate each Regulation resource's accuracy score. The accuracy score shall be the average of a delay score, correlation score, and energy score for each ten second interval. For purposes of setting the interval to be used for the correlation score and delay scores, PJM will use the maximum of the correlation score plus the delay score for each interval.

The Office of the Interconnection shall calculate the correlation score using the following statistical correlation function (r) that measures the delay in response between the Regulation signal and the resource change in output:

$$\text{Correlation Score} = r_{\text{Signal, Response}(\delta, \delta+5 \text{ Min}); \\ \delta=0 \text{ to } 5 \text{ Min}}$$

where δ is delay.

The Office of the Interconnection shall calculate the delay score using the following equation:

$$\text{Delay Score} = \text{Abs} ((\delta - 5 \text{ Minutes}) / (5 \text{ Minutes})).$$

The Office of the Interconnection shall calculate a energy score as a function of the difference in the energy provided versus the energy requested by the Regulation signal while scaling for the number of samples. The energy score is the absolute error (ϵ) as a function of the resource's Regulation capacity using the following equations:

$$\text{Energy Score} = 1 - 1/n \sum \text{Abs} (\text{Error});$$

$$\text{Error} = \text{Average of Abs} ((\text{Response} - \text{Regulation Signal}) / (\text{Hourly Average Regulation Signal})); \text{ and}$$

n = the number of samples in the hour and the energy.

The Office of the Interconnection shall calculate an accuracy score for each Regulation resource that is the average of the delay score, correlation score, and energy score for a five-minute period using the following equation where *the energy score, the delay score, and the correlation score are each weighted equally*:

$$\text{Accuracy Score} = \max ((\text{Delay Score}) + (\text{Correlation Score})) + (\text{Energy Score}).$$

The historic accuracy score will be based on a rolling average of the hourly accuracy scores, with consideration of the qualification score, as defined in the PJM Manuals.

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 *multiplied* by the historic accuracy score of the resource and multiplied by the unit-specific benefits factor for which the capability cost-based offer plus the performance 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.

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers is less than or equal to 1.0, then the three

suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

(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. PJM shall also (i) determine whether any resources were scheduled in the Day-ahead Energy Market to provide Black Start service, Reactive Services or transfer interface control during the Operating Day because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day in order to minimize the total cost of Operating Reserves associated with the provision of such services and reflect the most accurate possible expectation of real-time operating conditions in the day-ahead model, which resources would not have otherwise been committed in the day-ahead security-constrained dispatch and (ii) report on the day following the Operating Day the megawatt quantities scheduled in the Day-ahead Energy Market for the above-enumerated purposes for the entire RTO.

Except as provided in Section 3.2.3(n), 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, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load (net of operating Behind The Meter Generation) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

(e) 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 in the Day-ahead Energy Market plus any credit or change for quantity deviations, at PJM dispatch direction, from the Day-ahead Energy Market during the Operating Day at the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for segment 2 shall exclude start up (shutdown costs for 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), 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 Non-Synchronized Reserve in excess of the Non-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, Non-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, Non-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 $\{(LMP_{DMW} - AG) \times (URTLMP - UB)\}$, where:

LMP_{DMW} 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 and limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;

AG equals the actual hourly integrated output of the unit;

URLTMP 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 $URLTMP - UB$ 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, *and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output*, if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described 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) $\{(URLTMP - UDALMP) \times DAG\}$, or (ii) $\{(URLTMP - UB) \times DAG\}$ where:

URLTMP 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 $URLTMP - UDALMP$ and $URLTMP - UB$ 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.

(f-4) A Market Seller's wind generating unit that is pool-scheduled or self-scheduled and operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the 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 $\{(LMP_{DMW} - AG) \times (URTLMP - UB)\}$, where:

LMP_{DMW} equals the lesser of the PJM forecasted output for the unit or 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, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;

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.

In the event the Office of the Interconnection experiences a technical problem or malfunction with its wind forecasting tool that results in an erroneous forecast for a wind resource during a period of time for which the wind resource is eligible for lost opportunity cost, the Office of the Interconnection and the Market Seller will attempt to reach a mutually agreeable forecast value for settlement purposes. If the Office of the Interconnection and the Market Seller do not come to mutual agreement on an acceptable forecast value, the Office of the Interconnection shall utilize the forecast value that it determines is appropriate.

(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, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (1) 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 in subsection (h)(ii) below and in the PJM Manuals; (2) 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; (3) 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 (4) 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.

The costs associated with scheduling of units for Black Start service or testing of Black Start Units shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff.

Notwithstanding section (h)(1) above, as more fully set forth in the PJM Manuals, load deviations from the Day-ahead Energy Market shall not be assessed Operating Reserves charges to the extent attributable to reductions in the load of Price Responsive Demand that is in response to an increase in Locational Marginal Price from the Day-ahead Energy Market to the Real-time Energy Market and that is in accordance with a properly submitted PRD Curve.

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 buses 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 buses 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.

- (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 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 generation resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:

(i) real-time economic minimum $\leq$ 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum $\geq$ 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:

$$\text{Ramp_Request}_t = \frac{(\text{UDS}_{\text{target}}_{t-1} - \text{AOutput}_{t-1})}{(\text{UDSL}_{\text{time}}_{t-1})}$$

$$\text{RL_Desired}_t = \text{AOutput}_{t-1} + \left(\text{Ramp_Request}_t * \text{Case_Eff_time}_{t-1} \right)$$

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 generation resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the 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 its 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 $\leq 20\%$, 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 - Day-Ahead MWh.

(o-1) Dispatchable economic load reduction resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Economic load reduction resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations as described in this subsection and as further specified in the PJM Manuals.

The Desired MW quantity for such resources for each hour shall be the hourly integrated MW quantity to which the load reduction resource was dispatched for each hour (where the hourly integrated value is the average of the dispatched values as determined by the Office of the Interconnection for the resource for each hour).

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no balancing Operating Reserve deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the balancing Operating Reserve deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual reduction quantity). For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined in section 3.3A of this Appendix. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, 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, EKPC 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 except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, 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 that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM

Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. 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 resources 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 less the hourly integrated real-time LMP, with the exception of those hours in which the Non-Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone is not equal to zero. During such hours, Tier 1 Synchronized Reserve resources shall be compensated at the Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone for the lesser of the hourly integrated amount of Tier 1 Synchronized Reserve attributed to the resource as calculated by the Office of the Interconnection, or the actual amount of Tier 1 Synchronized Reserve provided should a Synchronized Reserve Event occur.

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 Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the operating day. The hourly Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of serving the next increment of demand for Synchronized Reserve in each Reserve Zone or Reserve Sub-zone, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve requirement in a Reserve Zone or Reserve Sub-zone cannot be met, the 5-minute clearing price shall be at least greater than or equal to the Synchronized Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the sum of the Synchronized Reserve Penalty Factor and the Primary Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the sum of the Primary Reserve Penalty Factor and the Synchronized Reserve Penalty Factor for that Reserve Zone or Reserve Sub-zone.

The Synchronized Reserve Penalty Factors shall each be phased in as described below:

- i. \$250/MWh for the 2012/2013 Delivery Year;
- ii. \$400/MWh for the 2013/2014 Delivery Year;
- iii. \$550/MWh for the 2014/2015 Delivery Year; and
- iv. \$850/MWh as of the 2015/2016 Delivery Year.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding \$1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Synchronized Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(e) In determining the 5-minute Synchronized Reserve 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 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 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 resource will be credited for Tier 2 Synchronized Reserve capacity in the amount that actually responded for the contiguous hours the resource was assigned Tier 2 Synchronized Reserve during which the event occurred, and 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 Reserve Zone and Reserve Sub-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.001 Non-Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-

Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. An Internal Market Buyer that does not meet its hourly Non-Synchronized Reserve Obligation shall be charged for the Non-Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Non-Synchronized Reserve Market Clearing Price determined in accordance with paragraph (c) of this section, plus the amounts, if any, described in paragraph (f) of this section.

(b) Credits for Non-Synchronized Reserve provided by generation resources that are not operating for energy at the direction of the Office of the Interconnection specifically for the purpose of providing Non-Synchronized Reserve shall be the higher of (i) the Non-Synchronized Reserve Market Clearing Price or (ii) the specific opportunity cost of the generation resource supplying the increment of Non-Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the operating day. The hourly Non-Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve requirement. When the Primary Reserve requirement in a Reserve Zone or Reserve Sub-zone cannot be met at a price less than or equal to the Primary Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve will be determined as the Primary Reserve Penalty Factor. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the Primary Reserve Penalty Factor for that Reserve Zone or Reserve Sub-zone.

The Primary Reserve Penalty Factors shall each be phased in as described below:

- i. \$250/MWh for the 2012/2013 Delivery Year;
- ii. \$400/MWh for the 2013/2014 Delivery Year;
- iii. \$550/MWh for the 2014/2015 Delivery Year; and
- iv. \$850/MWh as of the 2015/2016 Delivery Year.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding \$1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Primary Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(d) In determining the 5-minute Non-Synchronized Reserve clearing price, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves shall be equal to 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 Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Non-Synchronized Reserve and that 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 Non-Synchronized Reserve and shall be equal to 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 Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

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

(g) The magnitude of response to a Non-Synchronized Reserve Event by a generation resource is the difference between the generation resource's output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output at the start of the event is defined as the lowest telemetered generator resource output between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output 10 minutes after the start of the event is defined as the greatest generator resource output achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(h) In the event a generation resource that has been assigned by the Office of the Interconnection to provide Non-Synchronized Reserve fails to provide the assigned amount of Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the contiguous hours the resource was assigned Non-Synchronized Reserve during which the event occurred.

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 $\{(LMP_{DMW} - AG) \times (URTLMP - UB)\}$

where:

LMP_{DMW} 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, *and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output*;

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, *limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output*, if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the 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) $\{(URTLMP - UDALMP) \times DAG\}$, or (ii) $\{(URTLMP - UB) \times DAG\}$ 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 $\{(AG - LMPDMW) \times (UB - URTLMP)\}$ 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 subsection (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of the Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. 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) When the Office of the Interconnection has implemented Emergency procedures, resources offering Emergency energy are eligible to set real-time Locational Marginal Prices, capped at the energy offer cap plus the sum of the applicable Reserve Penalty Factors, provided that the Emergency energy is needed to meet demand in the PJM Region.

(b) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each 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.

(c) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each 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.

(d) 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.

5.2 Transmission Congestion Credit Calculation.

5.2.1 Eligibility.

(a) Except as provided in Section 5.2.1(b), each holder of a Financial Transmission Right shall receive as a Transmission Congestion Credit a proportional share of the total Transmission Congestion Charges collected for each constrained hour.

(b) If a holder of a Financial Transmission Right between specified delivery and receipt buses acquired the Financial Transmission Right in a Financial Transmission Rights auction (the procedures for which are set forth in Part 7 of this Schedule 1) and (i) had an Increment Bid and/or Decrement Bid that was accepted by the Office of the Interconnection for an applicable hour in the Day-ahead Energy Market for delivery or receipt at or near delivery or receipt buses of the Financial Transmission Right; and (ii) the result of the acceptance of such Increment Bid or Decrement Bid is that the difference in Locational Marginal Prices in the Day-ahead Energy Market between such delivery and receipt buses is greater than the difference in Locational Marginal Prices between such delivery and receipt buses in the Real-time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit, associated with such Financial Transmission Right in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount that the Market Participant paid for the Financial Transmission Right in the Financial Transmission Rights Auction.

(c) For purposes of Section 5.2.1(b) a bus shall be considered at or near the Financial Transmission Right delivery or receipt bus if seventy-five percent or more of the energy injected or withdrawn at that bus and which is withdrawn or injected at any other bus is reflected in the constrained path between the subject Financial Transmission Right delivery and receipt buses that were acquired in the Financial Transmission Rights auction.

(d) The Market Monitoring Unit shall calculate Transmission Congestion Credits pursuant to this section and section VI of Attachment M – Appendix. 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 agrees with such calculation, then it shall impose the forfeiture of the Transmission Congestion Credit accordingly. If the Office of the Interconnection does not agree with the calculation, then it shall impose a forfeiture of Transmission Congestion Credit consistent with its determination. If the Market Monitoring Unit disagrees with the Office of the Interconnection's determination, it may exercise its powers to inform the Commission staff of its concerns and may request an adjustment. This provision is duplicated in section VI of Attachment M – Appendix. An FTR holder objecting to the application of this rule shall have recourse to the Commission for review of the application of the FTR forfeiture rule to its trading activity.

5.2.2 Financial Transmission Rights.

(a) Transmission Congestion Credits will be calculated based upon the Financial Transmission Rights held at the time of the constrained hour. Except as provided in subsection (e) below, Financial Transmission Rights shall be auctioned as set forth in Section 7.

(b) The hourly economic value of a Financial Transmission Right Obligation is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right. The hourly economic value of a Financial Transmission Right Obligation is positive (a benefit to the Financial Transmission Right holder) when the Day-ahead Congestion Price at the point of delivery is higher than the Day-ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Obligation is negative (a liability to the holder) when the Day-ahead Congestion Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.

(c) The hourly economic value of a Financial Transmission Right Option is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right when that difference is positive. The hourly economic value of a Financial Transmission Right Option is positive (a benefit to the Financial Transmission Right holder) when the Day-ahead Congestion Price at the point of delivery is higher than the Day-ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Option is zero (neither a benefit nor a liability to the holder) when the Day-ahead Congestion Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.

(d) In addition to transactions with PJMSettlement in the Financial Transmission Rights auctions administered by the Office of the Interconnection, a Financial Transmission Right, for its entire tenure or for a specified monthly period, may be sold or otherwise transferred to a third party by bilateral agreement, subject to compliance with such procedures as may be established by the Office of the Interconnection for verification of the rights of the purchaser or transferee.

(i) Market Participants may enter into bilateral agreements to transfer to a third party a Financial Transmission Right, for its entire tenure or for a specified monthly period. Such bilateral transactions shall be reported to the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules related to its eFTR tools.

(ii) For purposes of clarity, with respect to all bilateral transactions for the transfer of Financial Transmission Rights, the rights and obligations pertaining to the Financial Transmission Rights that are the subject of such a bilateral transaction shall pass to the buyer under the bilateral contract subject to the provisions of this Schedule. Such bilateral transactions shall not modify the location or reconfigure the Financial Transmission Rights. In no event shall the purchase and sale of a Financial Transmission Right pursuant to a bilateral transaction constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.

(iii) Consent of the Office of the Interconnection shall be required for a seller to transfer to a buyer any Financial Transmission Right Obligation. Such consent shall be based

upon the Office of the Interconnection's assessment of the buyer's ability to perform the obligations, including meeting applicable creditworthiness requirements, transferred in the bilateral contract. If consent for a transfer is not provided by the Office of the Interconnection, the title to the Financial Transmission Rights shall not transfer to the third party and the holder of the Financial Transmission Rights shall continue to receive all Transmission Congestion Credits attributable to the Financial Transmission Rights and remain subject to all credit requirements and obligations associated with the Financial Transmission Rights.

(iv) A seller under such a bilateral contract shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any charges associated with the transferred Financial Transmission Right and for which payment is not made to PJMSettlement by the buyer under such a bilateral transaction.

(v) All payments and related charges associated with such a bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by PJMSettlement or the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral contract reported to the Office of the Interconnection under this Schedule.

(vi) All claims regarding a default of a buyer to a seller under such a bilateral contract shall be resolved solely between the buyer and the seller.

(e) Network Service Users and Firm Transmission Customers that take service that sinks, sources in, or is transmitted through new PJM zones, at their election, may receive a direct allocation of Financial Transmission Rights instead of an allocation of Auction Revenue Rights. Network Service Users and Firm Transmission Customers may make this election for the succeeding two annual FTR auctions after the integration of the new zone into the PJM interchange energy market. Such election shall be made prior to the commencement of each annual FTR auction. For purposes of this election, the Allegheny Power Zone shall be considered a new zone with respect to the annual Financial Transmission Right auction in 2003 and 2004. Network Service Users and Firm Transmission Customers in new PJM zones that elect not to receive direct allocations of Financial Transmission Rights shall receive allocations of Auction Revenue Rights. During the annual allocation process, the Financial Transmission Right allocation for new PJM zones shall be performed simultaneously with the Auction Revenue Rights allocations in existing and new PJM zones. Prior to the effective date of the initial allocation of FTRs in a new PJM Zone, PJM shall file with FERC, under section 205 of the Federal Power Act, the FTRs and ARRs allocated in accordance with sections 5 and 7 of this Schedule 1.

(f) For Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through new PJM zones that elect to receive direct allocations of Financial Transmission Rights, Financial Transmission Rights shall be allocated using the same allocation methodology as specified for the allocation of Auction Revenue Rights in Section 7.4.2 and in accordance with the following:

(i) Subject to subsection (ii) of this section, all Financial Transmission Rights must be simultaneously feasible. If all Financial Transmission Right requests made when Financial Transmission Rights are allocated for the new zone are not feasible then Financial Transmission Rights are prorated and allocated in proportion to the MW level requested and in inverse proportion to the effect on the binding constraints.

(ii) If any Financial Transmission Right requests that are equal to or less than a Network Service User's Zonal Base Load for the Zone or fifty percent of its transmission responsibility for Non-Zone Network Load, or fifty percent of megawatts of firm service between the receipt and delivery points of Firm Transmission Customers, are not feasible in the annual allocation and auction processes due to system conditions, then PJM shall increase the capability limits of the binding constraints that would have rendered the Financial Transmission Rights infeasible to the extent necessary in order to allocate such Financial Transmission Rights without their being infeasible for all rounds of the annual allocation and auction processes, provided that this subsection (ii) shall not apply if the infeasibility is caused by extraordinary circumstances. Additionally, such increased limits shall be included in subsequent modeling during the Planning Year to support any incremental allocations of Auction Revenue Rights and monthly and balance of the Planning Period Financial Transmission Rights auctions; unless and to the extent those system conditions that contributed to infeasibility in the annual process are not extant for the time period subject to the subsequent modeling, such as would be the case, for example, if transmission facilities are returned to service during the Planning Year. In these cases, any increase in the capability limits taken under this subsection (ii) during the annual process will be removed from subsequent modeling to support any incremental allocations of Auction Revenue Rights and monthly and balance of the Planning Period Financial Transmission Rights auctions.

For the purposes of this subsection (ii), extraordinary circumstances shall mean an event of force majeure that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Financial Transmission Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule 1 of this Agreement. If PJM allocates Financial Transmission Rights as a result of this subsection (ii) that would not otherwise have been feasible, then PJM shall notify Members and post on its web site (a) the aggregate megawatt quantities, by sources and sinks, of such Financial Transmission Rights and (b) any increases in capability limits used to allocate such Financial Transmission Rights.

(iii) In the event that Network Load changes from one Network Service User to another after an initial or annual allocation of Financial Transmission Rights in a new zone, Financial Transmission Rights will be reassigned on a proportional basis from the Network Service User losing the load to the Network Service User that is gaining the Network Load.

(g) At least one month prior to the integration of a new zone into the PJM Interchange Energy Market, Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through the new zone, shall receive an initial allocation of Financial Transmission Rights that will be in effect from the date of the integration

of the new zone until the next annual allocation of Financial Transmission Rights and Auction Revenue Rights. Such allocation of Financial Transmission Rights shall be made in accordance with Section 5.2.2(f) of this Schedule.

(h) The following congestion charge crediting and uplift (hereinafter, “mitigation”) rules shall apply to each new zone first integrated on any date from May 1, 2004 through May 31, 2005 for which FERC orders such mitigation as a result of a filing for such zone of the type specified in subsection (g) above. Where FERC orders such mitigation, such rules shall remain in effect for such zone from the date of its integration through May 31, 2005. All such mitigation shall terminate for all such zones on May 31, 2005.

1.) Mitigation shall apply only to Long-Term Firm Point-to-Point Transmission Service customers in such a zone that did not receive an allocation of ARRs or FTRs, as applicable, equal to the ARRs or FTRs such customer requested in the allocation for such zone. Only pro-rated requests that complied with the source, sink, and service level limitations stated in section 7.4.2(f) are eligible for mitigation. Such mitigation shall continue for the period stated above if a customer eligible for mitigation renews or rolls over its service agreement, but shall no longer apply if such a customer redirects its service to alternate points on a firm basis.

2.) The affected customers that will receive mitigation will be notified by PJM of the MW amount of mitigation they will receive based on the difference between the amount of ARRs or FTRs requested and the amount of ARRs or FTRs awarded.

3.) Mitigation provided herein applies only to requests submitted and pro-rated in the interim or annual ARR/FTR allocation process conducted for such zones for the time period specified above.

4.) For each affected customer as described above, PJM each month will provide a mitigation credit to offset any congestion charges incurred by such customer in connection with the MW amount for the contract reservation eligible for mitigation as determined under subsection (2) above. In no event shall the amount of any such credit exceed the net amount of any congestion paid (after taking account of any congestion credits) by such customer during such month with respect to such identified MW amount.

5.) The total cost of all such credits for all mitigated customers in a zone each month shall be charged to and collected from all Network Integration Transmission Service and Long-Term Firm Point-to-Point Transmission Service customers within such zone that received ARRs or FTRs or that received mitigation under this subsection (h), in proportion to each such customer’s share of the total allocated ARR/FTR MWs (including mitigation MWs). Mitigation and uplift shall be determined separately for each such zone.

5.2.3 Target Allocation of Transmission Congestion Credits.

A Target Allocation of Transmission Congestion Credits for each entity holding a Financial Transmission Right shall be determined for each Financial Transmission Right. Each Financial

Transmission Right shall be multiplied by the Day-ahead Congestion Price differences for the receipt and delivery points associated with the Financial Transmission Right, calculated as the Day-ahead Congestion Price at the delivery point(s) minus the Day-ahead Congestion Price at the receipt point(s). For the purposes of calculating Transmission Congestion Credits, the Day-ahead Congestion Price of a Zone is calculated as the sum of the Day-ahead Congestion Price of each bus that comprises the Zone multiplied by the percent of annual peak load assigned to each node in the Zone. Commencing with the 2015/2016 Planning Period, for the purposes of calculating Transmission Congestion Credits, the Day-ahead Congestion Price of a Residual Metered Load aggregate is calculated as the sum of the Day-ahead Congestion Price of each bus that comprises the Residual Metered Load aggregate multiplied by the percent of the annual peak residual load assigned to each bus that comprises the Residual Metered Load aggregate. When the FTR Target Allocation is positive, the FTR Target Allocation is a credit to the FTR holder. When the FTR Target Allocation is negative, the FTR Target Allocation is a debit to the FTR holder if the FTR is a Financial Transmission Right Obligation. When the FTR Target Allocation is negative, the FTR Target Allocation is set to zero if the FTR is a Financial Transmission Right Option. The total Target Allocation for Network Service Users and Transmission Customers for each hour shall be the sum of the Target Allocations associated with all of the Network Service Users' or Transmission Customers' Financial Transmission Rights.

5.2.4 [Reserved.]

5.2.5 Calculation of Transmission Congestion Credits.

(a) The total of all the positive Target Allocations determined as specified above shall be compared to the total Transmission Congestion Charges in each hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market. If the total of the Target Allocations is less than the total of the Transmission Congestion Charges, the Transmission Congestion Credit for each entity holding an FTR shall be equal to its Target Allocation. All remaining Transmission Congestion Charges shall be distributed as described below in Section 5.2.6 "Distribution of Excess Congestion Charges."

(b) If the total of the Target Allocations is greater than the total Transmission Congestion Charges for the hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market, each holder of Financial Transmission Rights shall be assigned a share of the total Transmission Congestion Charges in proportion to its Target Allocations for Financial Transmission Rights which have a positive Target Allocation value. Financial Transmission Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Transmission Congestion Credit.

(c) At the end of a Planning Period if all FTR holders did not receive Transmission Congestion Credits equal to their Target Allocations, the Office of the Interconnection shall assess a charge equal to the difference between the Transmission Congestion Credit Target Allocations for all revenue deficient FTRs and the actual Transmission Congestion Credits allocated to those FTR holders. A charge assessed pursuant to this section shall also include any aggregate charge assessed pursuant to section 7.4.4(c) of Schedule 1 of this Agreement and shall be allocated to all FTR holders on a pro-rata basis according to the total Target Allocations for

all FTRs held at any time during the relevant Planning Period. The charge shall be calculated and allocated in accordance with the following methodology:

1. The Office of the Interconnection shall calculate the total amount of uplift required as {[sum of the total monthly deficiencies in FTR Target Allocations for the Planning Period + the sum of the ARR Target Allocation deficiencies determined pursuant to section 7.4.4(c) of Schedule 1 of this Agreement] – [sum of the total monthly excess ARR revenues and congestion charges for the Planning Period]}.

2. For each Market Participant that held an FTR during the Planning Period, the Office of the Interconnection shall calculate the total Target Allocation associated with all FTRs held by the Market Participant during the Planning Period provided that, the foregoing notwithstanding, if the total Target Allocation for an individual Market Participant calculated pursuant to this section is negative the Office of Interconnection shall set the value to zero.

3. The Office of the Interconnection shall then allocate an uplift charge to each Market Participant that held an FTR at any time during the Planning Period in accordance with the following formula: {[total uplift] * [total Target Allocation for all FTRs held by the Market Participant at any time during the Planning Period] / [total Target Allocations for all FTRs held by all PJM Market Participants at any time during the Planning Period]}.

5.2.6 Distribution of Excess Congestion Charges.

(a) Excess Transmission Congestion Charges accumulated in a month shall be distributed to each holder of Financial Transmission Rights in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the holder during that month as compared to its total Target Allocations for the month.

(b) After the excess Transmission Congestion Charge distribution described in Section 5.2.6(a) is performed, any excess Transmission Congestion Charges remaining at the end of a month shall be distributed to each holder of Financial Transmission Rights in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the holder during the current Planning Period, including previously distributed excess Transmission Congestion Charges, as compared to its total Target Allocation for the Planning Period.

(c) Any excess Transmission Congestion Charges remaining at the end of a Planning Period shall be distributed to each holder of Auction Revenue Rights in proportion to, but not more than, any Auction Revenue Right deficiencies for that Planning Period.

(d) Any excess Transmission Congestion Charges remaining after a distribution pursuant to subsection (c) of this section shall be distributed to all FTR holders on a pro-rata basis according to the total Target Allocations for all FTRs held at any time during the relevant Planning Period. Any allocation pursuant to this subsection (d) shall be conducted in accordance with the following methodology:

1. For each Market Participant that held an FTR during the Planning Period, the Office of the Interconnection shall calculate the total Target Allocation associated with all FTRs held by the Market Participant during the Planning Period, provided that, the foregoing notwithstanding, if the total Target Allocation for an individual Market Participant calculated pursuant to this section is negative the Office of the Interconnection shall set the value to zero.

2. The Office of the Interconnection shall then allocate an excess Transmission Congestion Charge credit to each Market Participant that held an FTR at any time during the Planning Period in accordance with the following formula: $\{[\text{total excess Transmission Congestion Charges remaining after distributions pursuant to subsection (a)-(c) of this section}] * [\text{total Target Allocation for all FTRs held by the Market Participant at any time during the Planning Period}] / [\text{total Target Allocations for all FTRs held by all PJM Market Participants at any time during the Planning Period}]\}$.

Section(s) of the
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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 Internal 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 the following for Regulation dispatched by the Office of the Interconnection to meet such obligation: (i) the capability Regulation market-clearing price determined in accordance with subsection (h) of this section; (ii) the amounts, if any, described in subsection (f) of this section; and (iii) the performance Regulation market-clearing price determined in accordance with subsection (g) of this section.

(b) Each Market Seller and Generating Market Buyer shall be credited for each of its resources supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection such that the calculated credit for each increment of Regulation provided by each resource shall be the higher of: (i) the Regulation market-clearing price; or (ii) the sum of the applicable Regulation offers for a resource determined pursuant to Section 3.2.2A.1 of this Schedule, the unit-specific shoulder hour opportunity costs described in subsection (e) of this section, the unit-specific inter-temporal opportunity costs, and the unit-specific opportunity costs discussed in subsection (d) of this section.

(c) The total 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. In accordance with the PJM Manuals, the total Regulation market-clearing price shall be calculated by optimizing the dispatch profile to obtain the lowest cost combination set of resources that satisfies the Regulation requirement. The market-clearing price for each regulating hour shall be equal to the average of all 5-minute clearing prices calculated during that hour. The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource 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 3.2.2A.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 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, 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.

For hydroelectric resources offering to sell Regulation in a regulating hour, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the full value of the Locational Marginal Price at that generation bus for each megawatt of Regulation capability.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the expected Locational Marginal Price at the generation bus for the hydroelectric resource and the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. Estimated opportunity costs shall be zero for hydroelectric resources for which the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those hours during which all available units at the hydroelectric resource were operating is higher than the actual Locational Marginal Price at the generator bus for the regulating hour.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating and the expected Locational Marginal Price at the generation bus for the hydroelectric resource. Estimated opportunity costs shall be zero for hydroelectric resources for which the actual Locational Marginal Price at the generator bus for the regulating hour is higher than the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those hours during which all available units at the hydroelectric resource were operating.

For the purpose of committing resources and setting Regulation market clearing prices, the Office of the Interconnection shall utilize day-ahead Locational Marginal Prices to calculate opportunity costs for hydroelectric resources. For the purposes of settlements, the Office of the Interconnection shall utilize the real-time Locational Marginal Prices to calculate opportunity costs for hydroelectric resources.

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

(e) In determining the credit under subsection (b) to a Market Seller or 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.

(g) To determine the performance Regulation market-clearing price for each Regulation Zone, the Office of the Interconnection shall adjust the submitted performance offer for each resource in accordance with the historical performance of that resource, the amount of Regulation that resource will be dispatched based on the ratio of control signals calculated by the Office of the Interconnection, and the unit-specific benefits factor described in subsection (j) of this section for which that resource is qualified. The maximum adjusted performance offer of all cleared resources will set the performance Regulation market-clearing price.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions, will be credited for Regulation performance *by multiplying the assigned MW(s) by the performance Regulation market-clearing price, by the ratio between the requested mileage for the Regulation dispatch signal assigned to the Regulation resource and the Regulation dispatch signal assigned to traditional resources, and by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.*

(h) The Office of the Interconnection shall divide each Regulation resource's capability offer by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score for the resource for the purposes of committing resources and setting the market clearing prices.

The Office of the Interconnection shall calculate the capability Regulation market-clearing price for each Regulation Zone by subtracting the performance Regulation market-clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the capability Regulation market clearing price for that market hour.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions will be credited for Regulation capability based on the assigned MW and the capability Regulation market-clearing price multiplied by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(i) In accordance with the processes described in the PJM Manuals, the Office of the Interconnection shall: (i) calculate inter-temporal opportunity costs for each applicable resource; (ii) include such inter-temporal opportunity costs in each applicable resource's offer to sell frequency Regulation service; and (iii) account for such inter-temporal opportunity costs in the Regulation market-clearing price.

(j) The Office of the Interconnection shall calculate a unit-specific benefits factor for each of the dynamic Regulation signal and traditional Regulation signal in accordance with the PJM Manuals. Each resource shall be assigned a unit-specific benefits factor based on their order in the merit order stack for the applicable Regulation signal. The unit-specific benefits factor is the point on the benefits factor curve that aligns with the last megawatt, adjusted by historical performance, that resource will add to the dynamic resource stack. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

(k) The Office of the Interconnection shall calculate each Regulation resource's accuracy score. The accuracy score shall be the average of a delay score, correlation score, and energy score for each ten second interval. For purposes of setting the interval to be used for the correlation score and delay scores, PJM will use the maximum of the correlation score plus the delay score for each interval.

The Office of the Interconnection shall calculate the correlation score using the following statistical correlation function (r) that measures the delay in response between the Regulation signal and the resource change in output:

$$\text{Correlation Score} = r_{\text{Signal, Response}(\delta, \delta+5 \text{ Min})};$$

$\delta=0 \text{ to } 5 \text{ Min}$

where δ is delay.

The Office of the Interconnection shall calculate the delay score using the following equation:

$$\text{Delay Score} = \text{Abs} ((\delta - 5 \text{ Minutes}) / (5 \text{ Minutes})).$$

The Office of the Interconnection shall calculate a energy score as a function of the difference in the energy provided versus the energy requested by the Regulation signal while scaling for the number of samples. The energy score is the absolute error (ϵ) as a function of the resource's Regulation capacity using the following equations:

$$\text{Energy Score} = 1 - 1/n \sum \text{Abs} (\text{Error});$$

$$\text{Error} = \text{Average of Abs} ((\text{Response} - \text{Regulation Signal}) / (\text{Hourly Average Regulation Signal})); \text{ and}$$

n = the number of samples in the hour and the energy.

The Office of the Interconnection shall calculate an accuracy score for each Regulation resource that is the average of the delay score, correlation score, and energy score for a five-minute period using the following equation where *the energy score, the delay score, and the correlation score are each weighted equally*:

$$\text{Accuracy Score} = \max ((\text{Delay Score}) + (\text{Correlation Score})) + (\text{Energy Score}).$$

The historic accuracy score will be based on a rolling average of the hourly accuracy scores, with consideration of the qualification score, as defined in the PJM Manuals.

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 *multiplied* by the historic accuracy score of the resource and multiplied by the unit-specific benefits factor for which the capability cost-based offer plus the performance 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.
- (iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the

Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

(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. PJM shall also (i) determine whether any resources were scheduled in the Day-ahead Energy Market to provide Black Start service, Reactive Services or transfer interface control during the Operating Day because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day in order to minimize the total cost of Operating Reserves associated with the provision of such services and reflect the most accurate possible expectation of real-time operating conditions in the day-ahead model, which resources would not have otherwise been committed in the day-ahead security-constrained dispatch and (ii) report on the day following the Operating Day the megawatt quantities scheduled in the Day-ahead Energy Market for the above-enumerated purposes for the entire RTO.

Except as provided in Section 3.2.3(n), 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, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load (net of operating Behind The Meter Generation) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

(e) 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 in the Day-ahead Energy Market plus any credit or change for quantity deviations, at PJM dispatch direction, from the Day-ahead Energy Market during the Operating Day at the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for segment 2 shall exclude start up (shutdown costs for 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), 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 Non-Synchronized Reserve in excess of the Non-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, Non-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, Non-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 $\{(LMP_{DMW} - AG) \times (URTLMP - UB)\}$, where:

LMP_{DMW} 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 *and limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output*;

AG equals the actual hourly integrated output of the unit;

URLTLP 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 $URLTLP - UB$ 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, *and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output*, if either of the following conditions occur:

- (i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described 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) $\{(URLTLP - UDALMP) \times DAG\}$, or (ii) $\{(URLTLP - UB) \times DAG\}$ where:

URLTLP 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.

(f-4) A Market Seller's wind generating unit that is pool-scheduled or self-scheduled and operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the 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 $\{(LMPDMW - AG) \times (URTLMP - UB)\}$, where:

LMPDMW equals the lesser of the PJM forecasted output for the unit or 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, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output;

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.

In the event the Office of the Interconnection experiences a technical problem or malfunction with its wind forecasting tool that results in an erroneous forecast for a wind resource during a period of time for which the wind resource is eligible for lost opportunity cost, the Office of the Interconnection and the Market Seller will attempt to reach a mutually agreeable forecast value for settlement purposes. If the Office of the Interconnection and the Market Seller do not come to mutual agreement on an acceptable forecast value, the Office of the Interconnection shall utilize the forecast value that it determines is appropriate.

(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, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (1) 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 in subsection (h)(ii) below and in the PJM Manuals; (2) 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; (3) 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 (4) 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.

The costs associated with scheduling of units for Black Start service or testing of Black Start Units shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff.

Notwithstanding section (h)(1) above, as more fully set forth in the PJM Manuals, load deviations from the Day-ahead Energy Market shall not be assessed Operating Reserves charges to the extent attributable to reductions in the load of Price Responsive Demand that is in response to an increase in Locational Marginal Price from the Day-ahead Energy Market to the Real-time Energy Market and that is in accordance with a properly submitted PRD Curve.

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 buses 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 buses 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.
 - (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 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 generation resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:

- (i) real-time economic minimum $\leq$ 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.
- (ii) real-time economic maximum $\geq$ 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:

$$\text{Ramp_Request}_t = \frac{(\text{UDStarget}_{t-1} - \text{AOutput}_{t-1})}{(\text{UDSLAtime}_{t-1})}$$

$$\text{RL_Desired}_t = \text{AOutput}_{t-1} + \left(\text{Ramp_Request}_t * \text{Case_Eff_time}_{t-1} \right)$$

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 generation resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the 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 $\leq$ 10, or its 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 $\leq 20\%$, 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 - Day-Ahead MWh.

(o-1) Dispatchable economic load reduction resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Economic load reduction resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations as described in this subsection and as further specified in the PJM Manuals.

The Desired MW quantity for such resources for each hour shall be the hourly integrated MW quantity to which the load reduction resource was dispatched for each hour (where the hourly integrated value is the average of the dispatched values as determined by the Office of the Interconnection for the resource for each hour).

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no balancing Operating Reserve deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the balancing Operating Reserve deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual

reduction quantity). For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined in section 3.3A of this Appendix. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, 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, *EKPC* 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 except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, 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 that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. 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 resources 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 less the hourly integrated real-time LMP, with the exception of those hours in which the Non-Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone is not equal to zero. During such hours, Tier 1 Synchronized Reserve resources shall be compensated at the Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone for the lesser of the hourly integrated amount of Tier 1 Synchronized Reserve attributed to the resource as calculated by the Office of the Interconnection, or the actual amount of Tier 1 Synchronized Reserve provided should a Synchronized Reserve Event occur.

- 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 Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the operating day. The hourly Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of serving the next increment of demand for Synchronized Reserve in each Reserve Zone or Reserve Sub-zone, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve requirement in a Reserve Zone or Reserve Sub-zone cannot be met, the 5-minute clearing price shall be at least greater than or equal to the Synchronized Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the sum of the Synchronized Reserve Penalty Factor and the Primary Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the sum of the Primary Reserve Penalty Factor and the Synchronized Reserve Penalty Factor for that Reserve Zone or Reserve Sub-zone.

The Synchronized Reserve Penalty Factors shall each be phased in as described below:

- i. \$250/MWh for the 2012/2013 Delivery Year;

- ii. \$400/MWh for the 2013/2014 Delivery Year;
- iii. \$550/MWh for the 2014/2015 Delivery Year; and
- iv. \$850/MWh as of the 2015/2016 Delivery Year.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding \$1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Synchronized Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(e) In determining the 5-minute Synchronized Reserve 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 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 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 resource will be credited for Tier 2 Synchronized Reserve capacity in the amount that actually responded for the contiguous hours the resource was assigned Tier 2 Synchronized Reserve during which the event occurred, and 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 Reserve Zone and Reserve Sub-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.001 Non-Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. An Internal Market Buyer that does not meet its hourly Non-Synchronized Reserve Obligation shall be charged for the Non-Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Non-Synchronized Reserve Market Clearing Price determined in accordance with paragraph (c) of this section, plus the amounts, if any, described in paragraph (f) of this section.

(b) Credits for Non-Synchronized Reserve provided by generation resources that are not operating for energy at the direction of the Office of the Interconnection specifically for the purpose of providing Non-Synchronized Reserve shall be the higher of (i) the Non-Synchronized Reserve Market Clearing Price or (ii) the specific opportunity cost of the generation resource supplying the increment of Non-Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each hour of the operating day. The hourly Non-Synchronized Reserve Market Clearing Price shall be calculated as the average of all 5-minute clearing prices calculated during the operating hour. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve requirement. When the Primary Reserve requirement in a Reserve Zone or Reserve Sub-zone cannot be met at a price less than or equal to the Primary Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve will be determined as the Primary Reserve Penalty Factor. If the

Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, the 5-minute clearing price shall be the Primary Reserve Penalty Factor for that Reserve Zone or Reserve Sub-zone.

The Primary Reserve Penalty Factors shall each be phased in as described below:

- i. \$250/MWh for the 2012/2013 Delivery Year;
- ii. \$400/MWh for the 2013/2014 Delivery Year;
- iii. \$550/MWh for the 2014/2015 Delivery Year; and
- iv. \$850/MWh as of the 2015/2016 Delivery Year.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding \$1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Primary Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(d) In determining the 5-minute Non-Synchronized Reserve clearing price, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves shall be equal to 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 Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Non-Synchronized Reserve and that 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 Non-Synchronized Reserve and shall be equal to 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 Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

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

(g) The magnitude of response to a Non-Synchronized Reserve Event by a generation resource is the difference between the generation resource's output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output at the start of the event is defined as the

lowest telemetered generator resource output between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output 10 minutes after the start of the event is defined as the greatest generator resource output achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(h) In the event a generation resource that has been assigned by the Office of the Interconnection to provide Non-Synchronized Reserve fails to provide the assigned amount of Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the contiguous hours the resource was assigned Non-Synchronized Reserve during which the event occurred.

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 $\{(LMP_{DMW} - AG) \times (URTLMP - UB)\}$

where:

LMP_{DMW} 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, *and shall be limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output*;

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, *limited to the lesser of the unit's Economic Maximum or the unit's Maximum Facility Output*, if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the 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) $\{(URTLMP - UDALMP) \times DAG\}$, or (ii) $\{(URTLMP - UB) \times DAG\}$ 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 $\{(AG - LMP_{DMW}) \times (UB - URTLMP)\}$ where:

AG equals the actual hourly integrated output of the unit;

LMP_{DMW} 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;

URLTMP 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 subsection (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of the Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. 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) When the Office of the Interconnection has implemented Emergency procedures, resources offering Emergency energy are eligible to set real-time Locational Marginal Prices, capped at the energy offer cap plus the sum of the applicable Reserve Penalty Factors, provided that the Emergency energy is needed to meet demand in the PJM Region.

(b) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each 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.

(c) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each 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.

(d) 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.

5.2 Transmission Congestion Credit Calculation.

5.2.1 Eligibility.

(a) Except as provided in Section 5.2.1(b), each holder of a Financial Transmission Right shall receive as a Transmission Congestion Credit a proportional share of the total Transmission Congestion Charges collected for each constrained hour.

(b) If a holder of a Financial Transmission Right between specified delivery and receipt buses acquired the Financial Transmission Right in a Financial Transmission Rights auction (the procedures for which are set forth in Part 7 of this Schedule 1) and (i) had an Increment Bid and/or Decrement Bid that was accepted by the Office of the Interconnection for an applicable hour in the Day-ahead Energy Market for delivery or receipt at or near delivery or receipt buses of the Financial Transmission Right; and (ii) the result of the acceptance of such Increment Bid or Decrement Bid is that the difference in Locational Marginal Prices in the Day-ahead Energy Market between such delivery and receipt buses is greater than the difference in Locational Marginal Prices between such delivery and receipt buses in the Real-time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit, associated with such Financial Transmission Right in such hour, in excess of one divided by the number of hours in the applicable month multiplied by the amount that the Market Participant paid for the Financial Transmission Right in the Financial Transmission Rights auction.

(c) For purposes of Section 5.2.1(b) a bus shall be considered at or near the Financial Transmission Right delivery or receipt bus if seventy-five percent or more of the energy injected or withdrawn at that bus and which is withdrawn or injected at any other bus is reflected in the constrained path between the subject Financial Transmission Right delivery and receipt buses that were acquired in the Financial Transmission Rights auction.

(d) The Market Monitoring Unit shall calculate Transmission Congestion Credits pursuant to this section and section VI of Attachment M – Appendix. 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 agrees with such calculation, then it shall impose the forfeiture of the Transmission Congestion Credit accordingly. If the Office of the Interconnection does not agree with the calculation, then it shall impose a forfeiture of Transmission Congestion Credit consistent with its determination. If the Market Monitoring Unit disagrees with the Office of the Interconnection's determination, it may exercise its powers to inform the Commission staff of its concerns and may request an adjustment. This provision is duplicated in section VI of Attachment M – Appendix. An FTR holder objecting to the application of this rule shall have recourse to the Commission for review of the application of the FTR forfeiture rule to its trading activity.

5.2.2 Financial Transmission Rights.

- (a) Transmission Congestion Credits will be calculated based upon the Financial Transmission Rights held at the time of the constrained hour. Except as provided in subsection (e) below, Financial Transmission Rights shall be auctioned as set forth in Section 7.
- (b) The hourly economic value of a Financial Transmission Right Obligation is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right. The hourly economic value of a Financial Transmission Right Obligation is positive (a benefit to the Financial Transmission Right holder) when the Day-ahead Congestion Price at the point of delivery is higher than the Day-ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Obligation is negative (a liability to the holder) when the Day-ahead Congestion Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.
- (c) The hourly economic value of a Financial Transmission Right Option is based on the Financial Transmission Right MW reservation and the difference between the Day-ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right when that difference is positive. The hourly economic value of a Financial Transmission Right Option is positive (a benefit to the Financial Transmission Right holder) when the Day-ahead Congestion Price at the point of delivery is higher than the Day-ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Option is zero (neither a benefit nor a liability to the holder) when the Day-ahead Price at the point of receipt is higher than the Day-ahead Congestion Price at the point of delivery.
- (d) In addition to transactions with PJMSettlement in the Financial Transmission Rights auctions administered by the Office of the Interconnection, a Financial Transmission Right, for its entire tenure or for a specified monthly period, may be sold or otherwise transferred to a third party by bilateral agreement, subject to compliance with such procedures as may be established by the Office of the Interconnection for verification of the rights of the purchaser or transferee.
- (i) Market Participants may enter into bilateral agreements to transfer to a third party a Financial Transmission Right, for its entire tenure or for a specified monthly period. Such bilateral transactions shall be reported to the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules related to its eFTR tools.
 - (ii) For purposes of clarity, with respect to all bilateral transactions for the transfer of Financial Transmission Rights, the rights and obligations pertaining to the Financial Transmission Rights that are the subject of such a bilateral transaction shall pass to the buyer under the bilateral contract subject to the provisions of this Schedule. Such bilateral transactions shall not modify the location or reconfigure the Financial Transmission Rights. In no event shall the purchase and sale of a Financial Transmission Right pursuant to a bilateral transaction constitute a transaction with PJMSettlement or a transaction in any auction under this Schedule.

- (iii) Consent of the Office of the Interconnection shall be required for a seller to transfer to a buyer any Financial Transmission Right Obligation. Such consent shall be based upon the Office of the Interconnection's assessment of the buyer's ability to perform the obligations, including meeting applicable creditworthiness requirements, transferred in the bilateral contract. If consent for a transfer is not provided by the Office of the Interconnection, the title to the Financial Transmission Rights shall not transfer to the third party and the holder of the Financial Transmission Rights shall continue to receive all Transmission Congestion Credits attributable to the Financial Transmission Rights and remain subject to all credit requirements and obligations associated with the Financial Transmission Rights.
 - (iv) A seller under such a bilateral contract shall guarantee and indemnify the Office of the Interconnection, PJMSettlement, and the Members for the buyer's obligation to pay any charges associated with the transferred Financial Transmission Right and for which payment is not made to PJMSettlement by the buyer under such a bilateral transaction.
 - (v) All payments and related charges associated with such a bilateral contract shall be arranged between the parties to such bilateral contract and shall not be billed or settled by PJMSettlement or the Office of the Interconnection. The LLC, PJMSettlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under such a bilateral contract reported to the Office of the Interconnection under this Schedule.
 - (vi) All claims regarding a default of a buyer to a seller under such a bilateral contract shall be resolved solely between the buyer and the seller.
- (e) Network Service Users and Firm Transmission Customers that take service that sinks, sources in, or is transmitted through new PJM zones, at their election, may receive a direct allocation of Financial Transmission Rights instead of an allocation of Auction Revenue Rights. Network Service Users and Firm Transmission Customers may make this election for the succeeding two annual FTR auctions after the integration of the new zone into the PJM Interchange Energy Market. Such election shall be made prior to the commencement of each annual FTR auction. For purposes of this election, the Allegheny Power Zone shall be considered a new zone with respect to the annual Financial Transmission Right auction in 2003 and 2004. Network Service Users and Firm Transmission Customers in new PJM zones that elect not to receive direct allocations of Financial Transmission Rights shall receive allocations of Auction Revenue Rights. During the annual allocation process, the Financial Transmission Right allocation for new PJM zones shall be performed simultaneously with the Auction Revenue Rights allocations in existing and new PJM zones. Prior to the effective date of the initial allocation of FTRs in a new PJM Zone, PJM shall file with FERC, under section 205 of the Federal Power Act, the FTRs and ARRs allocated in accordance with sections 5 and 7 of this Schedule 1.

(f) For Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through new PJM zones, that elect to receive direct allocations of Financial Transmission Rights, Financial Transmission Rights shall be allocated using the same allocation methodology as is specified for the allocation of Auction Revenue Rights in Section 7.4.2 and in accordance with the following:

- (i) Subject to subsection (ii) of this section, all Financial Transmission Rights must be simultaneously feasible. If all Financial Transmission Right requests made when Financial Transmission Rights are allocated for the new zone are not feasible then Financial Transmission Rights are prorated and allocated in proportion to the MW level requested and in inverse proportion to the effect on the binding constraints.
- (ii) If any Financial Transmission Right requests that are equal to or less than a Network Service User's Zonal Base Load for the Zone or fifty percent of its transmission responsibility for Non-Zone Network Load, or fifty percent of megawatts of firm service between the receipt and delivery points of Firm Transmission Customers, are not feasible in the annual allocation and auction processes due to system conditions, then PJM shall increase the capability limits of the binding constraints that would have rendered the Financial Transmission Rights infeasible to the extent necessary in order to allocate such Financial Transmission Rights without their being infeasible for all rounds of the annual allocation and auction processes, provided that this subsection (ii) shall not apply if the infeasibility is caused by extraordinary circumstances. Additionally, such increased limits shall be included in subsequent modeling during the Planning Year to support any incremental allocations of Auction Revenue Rights and monthly and balance of the Planning Period Financial Transmission Rights auctions; unless and to the extent those system conditions that contributed to infeasibility in the annual process are not extant for the time period subject to the subsequent modeling, such as would be the case, for example, if transmission facilities are returned to service during the Planning Year. In these cases, any increase in the capability limits taken under this subsection (ii) during the annual process will be removed from subsequent modeling to support any incremental allocations of Auction Revenue Rights and monthly and balance of the Planning Period Financial Transmission Rights auctions.

For the purposes of this subsection (ii), extraordinary circumstances shall mean an event of force majeure that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Financial Transmission Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule 1 of this Agreement. If PJM allocates Financial Transmission Rights as a result of this subsection (ii) that would not otherwise have been feasible, then PJM shall notify Members and post on its web site (a) the aggregate megawatt quantities, by

sources and sinks, of such Financial Transmission Rights and (b) any increases in capability limits used to allocate such Financial Transmission Rights.

- (iii) In the event that Network Load changes from one Network Service User to another after an initial or annual allocation of Financial Transmission Rights in a new zone, Financial Transmission Rights will be reassigned on a proportional basis from the Network Service User losing the load to the Network Service User that is gaining the Network Load.

(g) At least one month prior to the integration of a new zone into the PJM Interchange Energy Market, Network Service Users and Firm Transmission Customers that take service that sinks in, sources in, or is transmitted through the new zone, shall receive an initial allocation of Financial Transmission Rights that will be in effect from the date of the integration of the new zone until the next annual allocation of Financial Transmission Rights and Auction Revenue Rights. Such allocation of Financial Transmission Rights shall be made in accordance with Section 5.2.2(f) of this Schedule.

(h) The following congestion charge crediting and uplift (hereinafter, "mitigation") rules shall apply to each new zone first integrated on any date from May 1, 2004 through May 31, 2005 for which FERC orders such mitigation as a result of a filing for such zone of the type specified in subsection (g) above. Where FERC orders such mitigation, such rules shall remain in effect for such zone from the date of its integration through May 31, 2005. All such mitigation shall terminate for all such zones on May 31, 2005.

- 1.) Mitigation shall apply only to Long-Term Firm Point-to-Point Transmission Service customers in such a zone that did not receive an allocation of ARRs or FTRs, as applicable, equal to the ARRs or FTRs such customer requested in the allocation for such zone. Only pro-rated requests that complied with the source, sink, and service level limitations stated in section 7.4.2(f) are eligible for mitigation. Such mitigation shall continue for the period stated above if a customer eligible for mitigation renews or rolls over its service agreement, but shall no longer apply if such a customer redirects its service to alternate points on a firm basis.
- 2.) The affected customers that will receive mitigation will be notified by PJM of the MW amount of mitigation they will receive based on the difference between the amount of ARRs or FTRs requested and the amount of ARRs or FTRs awarded.
- 3.) Mitigation provided herein applies only to requests submitted and pro-rated in the interim or annual ARR/FTR allocation process conducted for such zones for the time period specified above.
- 4.) For each affected customer as described above, PJM each month will provide a mitigation credit to offset any congestion charges incurred by such customer in connection with the MW amount for the contract reservation eligible for mitigation as determined under subsection (2) above. In no event shall the

amount of any such credit exceed the net amount of any congestion paid (after taking account of any congestion credits) by such customer during such month with respect to such identified MW amount.

- 5.) The total cost of all such credits for all mitigated customers in a zone each month shall be charged to and collected from all Network Integration Transmission Service and Long-Term Firm Point-to-Point Transmission Service customers within such zone that received ARRs or FTRs or that received mitigation under this subsection (h), in proportion to each such customer's share of the total allocated ARR/FTR MWs (including mitigation MWs). Mitigation and uplift shall be determined separately for each such zone.

5.2.3 Target Allocation of Transmission Congestion Credits.

A Target Allocation of Transmission Congestion Credits for each entity holding a Financial Transmission Right shall be determined for each Financial Transmission Right. Each Financial Transmission Right shall be multiplied by the Day-ahead Congestion Price differences for the receipt and delivery points associated with the Financial Transmission Right, calculated as the Day-ahead Congestion Price at the delivery point(s) minus the Day-ahead Congestion Price at the receipt point(s). For the purposes of calculating Transmission Congestion Credits, the Day-ahead Congestion Price of a Zone is calculated as the sum of the Day-ahead Congestion Price of each bus that comprises the Zone multiplied by the percent of annual peak load assigned to each node in the Zone. Commencing with the 2015/2016 Planning Period, for the purposes of calculating Transmission Congestion Credits, the Day-ahead Congestion Price of a Residual Metered Load aggregate is calculated as the sum of the Day-ahead Congestion Price of each bus that comprises the Residual Metered Load aggregate multiplied by the percent of the annual peak residual load assigned to each bus that comprises the Residual Metered Load aggregate. When the FTR Target Allocation is positive, the FTR Target Allocation is a credit to the FTR holder. When the FTR Target Allocation is negative, the FTR Target Allocation is a debit to the FTR holder if the FTR is a Financial Transmission Right Obligation. When the FTR Target Allocation is negative, the FTR Target Allocation is set to zero if the FTR is a Financial Transmission Right Option. The total Target Allocation for Network Service Users and Transmission Customers for each hour shall be the sum of the Target Allocations associated with all of the Network Service Users' or Transmission Customers' Financial Transmission Rights.

5.2.4 [Reserved.]

5.2.5 Calculation of Transmission Congestion Credits.

- (a) The total of all the positive Target Allocations determined as specified above shall be compared to the total Transmission Congestion Charges in each hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market. If the total of the Target Allocations is less than the total of the Transmission Congestion Charges, the Transmission Congestion Credit for each entity holding an FTR shall be equal to its Target Allocation. All remaining Transmission Congestion Charges shall be distributed as described below in Section 5.2.6 "Distribution of Excess Congestion Charges."

(b) If the total of the Target Allocations is greater than the total Transmission Congestion Charges for the hour resulting from both the Day-ahead Energy Market and the Real-time Energy Market, each holder of Financial Transmission Rights shall be assigned a share of the total Transmission Congestion Charges in proportion to its Target Allocations for Financial Transmission Rights which have a positive Target Allocation value. Financial Transmission Rights which have a negative Target Allocation value are assigned the full Target Allocation value as a negative Transmission Congestion Credit.

(c) At the end of a Planning Period if all FTR holders did not receive Transmission Congestion Credits equal to their Target Allocations, the Office of the Interconnection shall assess a charge equal to the difference between the Transmission Congestion Credit Target Allocations for all revenue deficient FTRs and the actual Transmission Congestion Credits allocated to those FTR holders. A charge assessed pursuant to this section shall also include any aggregate charge assessed pursuant to section 7.4.4(c) of Schedule 1 of this Agreement and shall be allocated to all FTR holders on a pro-rata basis according to the total Target Allocations for all FTRs held at any time during the relevant Planning Period. The charge shall be calculated and allocated in accordance with the following methodology:

1. The Office of the Interconnection shall calculate the total amount of uplift required as $\{[\text{sum of the total monthly deficiencies in FTR Target Allocations for the Planning Period} + \text{the sum of the ARR Target Allocation deficiencies determined pursuant to section 7.4.4(c) of Schedule 1 of this Agreement}] - [\text{sum of the total monthly excess ARR revenues and congestion charges for the Planning Period}]\}$.
2. For each Market Participant that held an FTR during the Planning Period, the Office of the Interconnection shall calculate the total Target Allocation associated with all FTRs held by the Market Participant during the Planning Period, provided that, the foregoing notwithstanding, if the total Target Allocation for an individual Market Participant calculated pursuant to this section is negative the Office of Interconnection shall set the value to zero.
3. The Office of the Interconnection shall then allocate an uplift charge to each Market Participant that held an FTR at any time during the Planning Period in accordance with the following formula: $\{[\text{total uplift}] * [\text{total Target Allocation for all FTRs held by the Market Participant at any time during the Planning Period}] / [\text{total Target Allocations for all FTRs held by all PJM Market Participants at any time during the Planning Period}]\}$.

5.2.6 Distribution of Excess Congestion Charges.

(a) Excess Transmission Congestion Charges accumulated in a month shall be distributed to each holder of Financial Transmission Rights in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the holder during that month as compared to its total Target Allocations for the month.

(b) After the excess Transmission Congestion Charge distribution described in Section 5.2.6(a) is performed, any excess Transmission Congestion Charges remaining at the end of a month shall be distributed to each holder of Financial Transmission Rights in proportion to, but not more than, any deficiency in the share of Transmission Congestion Charges received by the holder during the current Planning Period, including previously distributed excess Transmission Congestion Charges, as compared to its total Target Allocation for the Planning Period.

(c) Any excess Transmission Congestion Charges remaining at the end of a Planning Period shall be distributed to each holder of Auction Revenue Rights in proportion to, but not more than, any Auction Revenue Right deficiencies for that Planning Period.

(d) Any excess Transmission Congestion Charges remaining after a distribution pursuant to subsection (c) of this section shall be distributed to all FTR holders on a pro-rata basis according to the total Target Allocations for all FTRs held at any time during the relevant Planning Period. Any allocation pursuant to this subsection (d) shall be conducted in accordance with the following methodology:

1. For each Market Participant that held an FTR during the Planning Period, the Office of the Interconnection shall calculate the total Target Allocation associated with all FTRs held by the Market Participant during the Planning Period, provided that, the foregoing notwithstanding, if the total Target Allocation for an individual Market Participant calculated pursuant to this section is negative the Office of the Interconnection shall set the value to zero.
2. The Office of the Interconnection shall then allocate an excess Transmission Congestion Charge credit to each Market Participant that held an FTR at any time during the Planning Period in accordance with the following formula: $\{[\text{total excess Transmission Congestion Charges remaining after distributions pursuant to subsection (a)-(c) of this section}] * [\text{total Target Allocation for all FTRs held by the Market Participant at any time during the Planning Period}] / [\text{total Target Allocations for all FTRs held by all PJM Market Participants at any time during the Planning Period}]\}$.