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

James M. Burlew
Counsel
Phone (610) 666-4345 | Fax (610) 666-8211

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Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E. Room 1A
Washington, D.C. 20426

Re: PJM Interconnection, L.L.C., Docket No. ER12-___
Order No. 755 Compliance Filing

Dear Secretary Bose:

In compliance with the Federal Energy Regulatory Commission's ("Commission's" or "FERC's") Order No. 755,[1] PJM Interconnection, L.L.C. ("PJM") hereby submits revisions to the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement") and PJM Open Access Transmission ("Tariff"). Specifically, PJM submits proposed revisions to various sections in Schedule 1 of the Operating Agreement, Attachment K – Appendix of the Tariff,[2] and Schedule 3 of the Tariff to establish a two-part compensation methodology for the provision of frequency regulation service consistent with the requirements of Order No. 755. PJM requests an effective date of October 1, 2012.[3]

PJM has initiated this compliance filing significantly before the Commission's April 30, 2012 date set forth in Order No. 755. PJM fully supports the Commission's Order No. 755 reforms and wishes to initiate the Commission's "pay-for-performance" goal as well as its elimination of its uplift payments ("Make-whole Payments") as early as possible. PJM has received significant expressions of interest in these reforms from a variety of innovative entrepreneurs as evidenced in this rulemaking docket[4] through the letter of the Electricity Storage Association filed with the Commission on May 2, 2011 as well as the Comments filed with the Commission by various other entities.[5] PJM is

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[1] *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, Order No. 755, 137 FERC ¶ 61,064 (2011) (the "Order" or "Order No. 755").

[2] Schedule 1 of the Operating Agreement and Attachment K-Appendix of the Tariff are identical. For convenience, PJM will cite only to the Operating Agreement Schedule 1 sections. In each case, however, such references are intended to address the same changes to the identically numbered sections of Attachment K – Appendix of the Tariff and Schedule 1 of the Operating Agreement.

[3] PJM must implement its proposed revisions on the first day of a month to properly align with PJM's billing cycle.

[4] Docket No. RM11-7, *et al*.

[5] *See Frequency Regulation Compensation in the Organized Wholesale Power Markets*, Comments of ENABLA Power Networks, Docket No. RM11-7, *et al* (May 2, 2011). *See also Frequency Regulation*

making this compliance filing early because the Commission has yet to act on PJM's Order No. 719 compliance filing.[6] Unfortunately, the lack of Commission direction on key aspects of PJM's Order No. 719 compliance filing, as detailed below, significantly complicates PJM having in place the necessary markets and operations platforms to meet the Commission's Order No. 755 goals seeking to eliminate Make-whole Payments and ensure a jointly optimized dispatch of energy, regulation, and reserves. Accordingly, in order to meet the Commission's October 29, 2012 date for compliance with Order No. 755, PJM will need the additional time, which this early filing and timely Commission action would provide to both implement the changes necessary to establish the software platform detailed in PJM's Order No. 719 compliance filing to ensure Order No. 755 compliance and upon which to train both dispatchers and market participants on the new market changes. PJM explains these challenges below.

PJM has designed this filing respecting that the Commission has not resolved certain issues which have been pending for some time in PJM's Order No. 719 compliance docket concerning shortage pricing. As a result, PJM sets forth in herein alternate compliance paths. Although involving different levels of complexity and challenge, each path will enable PJM to implement the platform necessary to meet Order No. 755 compliance, while also ensuring that there is no ambiguity as to the rules in place during times of reserve shortage. As described herein, PJM's preferred option (the "Market-based Pricing Option") synchronizes resolution of these two requirements based on timely Commission action on the Order No. 719 Compliance Filing. The second option (the "Administrative Pricing Option") provides a "patch," indeed a notably sub-optimal one, to provide: (1) rules to address dispatch of regulation services during the majority of hours; and (2) a necessary separate and distinct set of rules to address compensation during times of operating reserve shortage. The pros and cons of each option are discussed in detail in this compliance filing. Nevertheless, because of the complex implementation issues, including the need to design and test the complex software modifications involved, and ensure proper training of PJM's dispatchers and market participants, PJM requests an order from the Commission by May 18, 2012, on this compliance filing including a clear direction as to whether PJM should pursue the Market-based Pricing Option or the Administrative Cap Option. Without such direction, it will be impossible for PJM to meet the Order No. 755 effective date of October 29, 2012 as PJM has not been able, to date, to move forward on developing the platform needed to implement the joint optimization of energy, regulation, and operating reserves both during normal system conditions and during times of reserve shortage as requested in PJM's pending Order No. 719 compliance filing.[7]

Compensation in the Organized Wholesale Power Markets, Comments of Beacon Power Corporation, Docket No. RM11-7, *et al* (May 2, 2011).

[6] This filing was submitted on June 18, 2010. *PJM Interconnection, L.L.C.'s Order No. 719 Compliance Filing*, Docket No. ER09-1063-004 (June 18, 2010) ("Order No. 719 Compliance Filing").

[7] While PJM's preferred approach, the Market-based Pricing Option, anticipates the Commission accepting all material elements of PJM's Shortage Pricing Compliance Filing, PJM concedes that not all elements

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of this filing must necessarily be accepted immediately for PJM to implement its preferred Market-based Pricing Option. Those elements which could be held over for further Commission review and consideration are set forth in Part III of this pleading.

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I. BACKGROUND AND ORDER NO. 755 REQUIREMENTS

In Order No. 755, the Commission directed each regional transmission organization ("RTO") and independent system operator ("ISO") to submit a compliance filing to modify their existing tariffs to provide for a two-part payment to frequency regulation resources.[8] The first part of the two-part payment must "be a capacity payment, or option payment, for a resource keeping its capacity in reserve in the event that it is needed to provide real-time frequency regulation service."[9] The second element of the two-part payment is "a performance payment that reflects the amount of work each resource performs in real-time."[10]

The Commission correctly found that presently PJM does not apply the opportunity cost payment uniformly to all cleared resources, but rather provides ex post unit-specific opportunity cost payments.[11] Moreover, the Commission opined that PJM's compensation method of providing the ex post Make-whole Payments "fails to reflect the marginal cost (including opportunity cost) that determines the market-clearing price paid to all cleared suppliers."[12] The Commission therefore required that each RTO pay all cleared frequency regulation resources a uniform clearing price that includes the marginal resource's opportunity costs, thereby eliminating such after-the-fact Make-whole Payments.[13]

II. DESCRIPTION OF PROPOSED ORDER NO. 755 REVISIONS

PJM proposes to modify its Tariff and Operating Agreement to provide for a two-part payment to frequency regulation resources. PJM further proposes to modify its three-pivotal supplier test ("TPS Test") to incorporate performance offers. PJM also includes certain miscellaneous clean up revisions to the Tariff and Operating Agreement unrelated to PJM's compliance with Order No. 755. Finally, to eliminate the Make-whole Payment, PJM proposes that the Commission accept one of two sets of revisions to PJM's market rules to implement the joint optimization and pricing of energy, regulation, and reserves every five minutes. [14]

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[8] Order No. 755 at ¶ 197.

[9] Order No. 755 at ¶ 198.

[10] Order No. 755 at ¶ 199.

[11] Order No. 755 at ¶¶ 7, 18.

[12] Order No. 755 at ¶18.

[13] Order No. 755 at ¶ 99.

[14] The proposed Tariff and Operating Agreement language set forth under the Market-Based Pricing Option contains (1) the identical Tariff and Operating Agreement language pending in the Order No. 719 Compliance Filing; and (2) additional revisions necessary to effectuate the two-part compensation methodology to regulation resources required by Order No. 755. As a result, the Commission should take

A. Two-part Payment Methodology

1. Summary of Two-part Compensation Methodology

PJM proposes to revise its regulation compensation methodology to establish a two-part payment in compliance with the Commission's directives in Order No. 755. Under the proposed methodology, resources will submit to PJM a two-part offer to provide regulation that includes a price for regulation capability[15] and a price for performance. PJM will calculate an accuracy score that reflects a regulation resource's accuracy in increasing or decreasing its output to provide frequency regulation service in response to PJM's dispatch signal. Historical accuracy scores will be used to adjust the resource's capability offer and performance offer. These accuracy-adjusted offers and the resources' lost opportunity costs will be used in the regulation market-clearing process to calculate a performance market-clearing price and a capability market-clearing price based on lowest total expected costs. Each resource will be paid a uniform capability payment and performance payment based on the resource's actual performance and accuracy.

PJM's proposal recognizes that a resource's ability to accurately increase or decrease real power injections or withdrawals (i.e., performance) provides the core of the regulation product, but that a properly designed regulation market must also consider, and compensate for, the cost of reserving a resource to provide regulation service (i.e., capacity and lost opportunity costs). The revised rules emphasize performance in four ways:

1. the historical performance of each resource impacts its position in the merit order stack such that a high performing resource becomes more attractive to the clearing process;

2. after determining the lowest cost set of resources needed to meet the regulation requirements, the highest adjusted performance offer[16] will set the performance

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the record as it exists in the Order No. 719 Compliance Filing in addressing any issues associated with this aspect (i.e., the Tariff and Operating Agreement revisions for Order No. 719) of the Market Based Pricing Option.

[15] In Order No. 755 the Commission makes reference to "capacity" of regulating resources and a "capacity payment" to such resources. To avoid confusion with its Reliability Pricing Model capacity market and the payments associated with that market, PJM uses the term "capability" rather than "capacity" in its Tariff and Operating Agreement revisions and in its description of such proposed revisions in this transmittal letter.

[16] *See* § II(A)(4)(b) below for description of the accuracy-adjusted regulation capability offer and accuracy-adjusted regulation performance offer. PJM proposes to adjust a resource's capability and performance offer based on the resource's historical accuracy of providing Regulation service in response to PJM's dispatch signal that will be used to adjust the resource's Regulation capability offers and performance offers. PJM will increase the cost to provide service in a resource's offer if such resource historically performs poorly.

clearing price which ensures the performance offers for all cleared resources will be satisfied;

3. performance compensation is adjusted based on the actual performance of the resource during a particular period of time to reflect the benefit the resource provided to system control during that period; and

4. the expectation of performance is built into the market design because a resource could receive compensation below its offer for a given hour if it performs below its historical average.

Although the performance aspects of PJM's proposed frequency regulation market are paramount, the market will also set a capability clearing price to ensure the cost of reserving a resource to provide regulation will be met by the total compensation from both performance and capability. Such capability payments encourage those resources that could otherwise supply energy to participate in the regulation market by recognizing their lost opportunity costs of having not otherwise offered into the energy market. .

A regulation market design must strike the proper balance between incenting high performing resources to enter the market while at the same time retaining traditional resources in the market, many of which perform at a high level in today's regulation market. PJM's proposed two-part compensation methodology properly strikes this balance by emphasizing performance payments and ensuring adequate capability payments.

2. Empirical Proof of the Benefits of Improved Compensation for Frequency Regulation: The KEMA Report KEMA Report

PJM commissioned KEMA, Inc. ("KEMA") to conduct studies to better understand the operational relationship between fast-following and traditional regulating resources using PJM's new regulation control signals, referred to as the dynamic regulation signal[17] to complement the traditional regulation signal.[18] KEMA issued its report on December 19, 2011, which report was publicly posted and made available to stakeholders considering the changes proposed in this filing.[19]

The KEMA report outlines the way fast-ramping resources and more traditional regulation resources can complement each other and ensure the most efficient and

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[17] The dynamic regulation signal is referred to as the RegD signal in the PJM Manuals.

[18] The traditional regulation signal is referred to as the RegA signal in the PJM Manuals.

[19] *See* KEMA Inc., *KERMIT Study Report: To Determine the Effectiveness of the AGC in Controlling Fast and Conventional Resources in the PJM Frequency Regulation Market*, http://www.pjm.com/committees-and-groups/task-forces/~/media/committees-groups/task-forces/rpstf/postings/pjm-kema-final-study-report.ashx.

reliable provision of regulation service. The philosophy underlying the regulation signals is that the flexible, fast-ramping resources following the dynamic regulation signal should be utilized first to counteract sudden Area Control Error ("ACE") movements and then slowly reset to a midpoint – where they are ready to correct the next ACE movement – as the slower resources respond and fast-following resource as they reset. In short, the mix of resources can work together to recognize the need for fast-ramping resources to reset themselves while ACE is maintained. Similar complementary signals have traditionally been used to control resources with different response characteristics such as hydro and steam resources. The dynamic regulation signal has fast ramping characteristic and a short period for energy neutrality that aligns well with many new regulation technologies and some traditional resources.

Figure A below shows a KEMA study plot of scores on North American Electric Reliability Corporation ("NERC") Control Performance Standard 1 ("CPS1")[20] reliability criteria for a sample day. The study results demonstrate that the use of fast-following resources, in conjunction with traditional regulating resources, provided more accurate control of ACE, which will allow PJM to maintain similar CPS1 scores achieved today while reducing the total amount of regulation capacity required. ***In other words, fast-following resources decrease the total regulation requirements necessary to maintain reliability requirements, which in turn decreases the total cost of the regulation service and energy***.[21] Therefore, PJM believes that the implementation of enhanced, performance-based compensation for frequency regulation will benefit consumers by lowering overall costs and while incenting more effective frequency regulation.

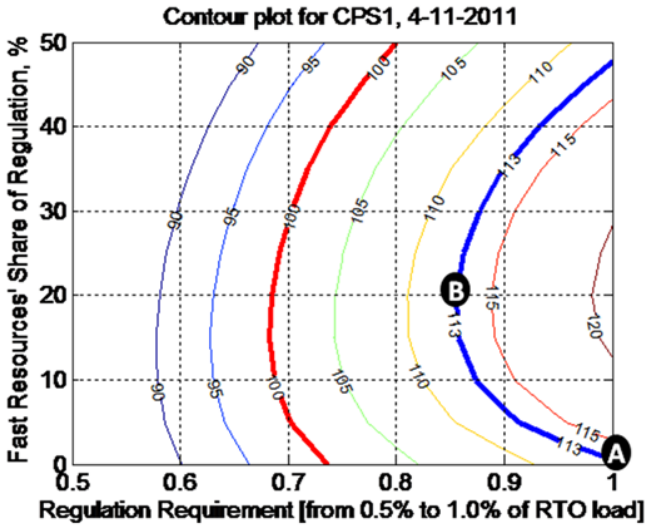

Figure A: Each contour line represents equivalent CPS 1 scores for the study day with various levels of fast-following resources and varying regulation requirements.

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[20] CPS1 refers to Requirement R1 of NERC Resource and Demand Balancing ("BAL") Reliability Standard BAL-001-0.1a.

[21] A reduction in total Regulation requirements allows the full capacity of traditional resources to remain in the PJM Interchange Energy Market which will lead to lower costs for energy.

Given that the operational characteristics of the traditional regulation signal and dynamic regulation signal complement one another, a blend of fast and traditional regulation resources provides the best control because the most beneficial aspects of each type of resource can be used for system control. Thus, as opposed to traditional resources providing all the regulation service, as is the case today, the first megawatt of fast-following regulation provides more benefit than the second megawatt. The plot above shows that the total amount of regulation capacity required in PJM to maintain similar CPS1 scores achieved today continually declines between points A and B (i.e., *Regulation Requirement*, which is on the X axis, decreased from one percent (1%) to approximately point eighty-five percent (0.85%) of the total load). However, as can be expected with a comparison of the optimal mix of resources, eventually the rate of decline decreases incrementally as more fast-following regulation resources are utilized in the PJM market. Consequently, at point B (i.e., the point where traditional and fast-following resources' share of the regulation market is, respectively, eighty percent and twenty percent), a megawatt of fast-following regulation and a megawatt of traditional regulation have the equivalent impact on system control and, therefore, dispatching fast-following regulation has no greater benefit than using traditional regulation.

PJM used the results of the KEMA analysis to determine the proper relationship between the traditional regulation signal and dynamic regulation signal, and to determine the point at which these various resources have an equivalent impact on system control. PJM proposes to use a benefits factor in the regulation clearing process to reflect the operational relationship between the traditional regulation signal and dynamic regulation signal. The benefits factor creates a common basis for the clearing engine to consider the impact that each resource will have on system control. This apples-to-apples comparison ensures the appropriate balance of resources following the traditional regulation signal and dynamic regulation signal will clear in the market and allows uniform clearing prices to be set for all resources.

Analysis of the entire data set from the KEMA studies indicates that the first megawatt of fast-following regulation will offset roughly three megawatts of traditional regulation. Additionally, the point B will be between twenty and twenty-five percent of fast following resources with a reduction in the regulation requirement also between twenty and twenty-five percent. In other words, with twenty percent of the regulation requirement provided by fast-following resources, the overall PJM regulation requirement will be reduced by roughly twenty percent. This relationship, which is represented by the benefits factor, may change from time to time based on the operational characteristics of the regulation signals and the resources providing regulation, therefore, PJM proposes to maintain the benefits factor in Manual 11, Section 3.

PJM's proposed performance-based two-part payment methodology will appropriately compensate each regulation resource for the benefit it provides to system control and meet the goals set forth by the Commission in its Order No. 755. This will incent the highest value resources to participate in PJM's regulation Market which will in turn lead to a lower overall regulation requirement to achieve reliable system control.

3. Regulation Capacity Payment

a) Uniform Payment for Regulation Capacity

In Order No. 755, the Commission required that each RTO pay all cleared frequency regulation resources a uniform clearing price that includes the marginal resource's opportunity costs.[22] The Commission directed "all RTOs and ISOs with centrally procured frequency regulation resources [to] provide for such opportunity costs in their tariffs."[23] Moreover, the Commission expressed concern that PJM's present method of providing Make-whole Payments based on individual resource's opportunity costs results in a market-clearing price that fails to reflect the accurate marginal cost (including opportunity cost) because the opportunity cost of the resources that received the Make-whole Payments are not included in the uniform market clearing price calculation.[24] The Commission found that paying such an "…out of market of unit-specific opportunity cost, rather than a uniform clearing price, can result in the market basing the commitment of regulating units on [offers] that do not reflect the true cost of providing capacity, potentially leading to committing units with higher costs than other units not committed."[25] PJM concurs with the Commission's concern and took steps through the initiatives set forth in its Order No. 719 filing to move toward joint optimization of energy, regulation, and reserves and establish pricing mechanisms which are designed so that reserve prices do not simply collapse in times of reserve shortage.

Currently, to set the capability regulation market-clearing price, PJM ranks the regulation resources in the order of cost, based on the sum of a resource's opportunity costs and offers for capacity.[26] The highest ranked resource that clears is the marginal unit that sets the price for an hour.[27] Each resource is provided with a payment for capability equal to the regulation market-clearing price times the amount of regulation (in megawatts) provided,[28] with the significant exception of the units that receive the Make-whole Payments. Order No. 755 requires elimination of these after-the-fact Make-whole Payments.[29]

PJM's proposed revisions to section 3.2.2 of Schedule 1 of the Operating Agreement establish a two-part payment methodology resulting in a uniform clearing

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[22] Order No. 755 at ¶ 99.

[23] *Id*.

[24] Order No. 755 at ¶18.

[25] Order No. 755 at ¶ 99.

[26] Operating Agreement, Schedule 1, § 3.2.2(c).

[27] *Id*.

[28] Operating Agreement, Schedule 1, § 3.2.2(b).

[29] In order to eliminate the Make-whole Payments, PJM must implement the joint optimization of energy and ancillary services as described below.

price that includes the marginal resource's opportunity costs as directed by the Commission. Under the proposed methodology, PJM will:

(1) include a resource's lost opportunity costs, accuracy-adjusted capability offer and accuracy-adjusted performance offer[30] to determine the incremental total cost for each resource in the ranking and clearing process with the highest ranked resource that clears setting a total regulation market-clearing price ("Total Regulation Market-clearing Price");[31]

(2) calculate a regulation performance clearing price based on the highest adjusted performance offer of the resources that cleared in step one (the "Performance Clearing Price");[32] and

(3) calculate a regulation capability clearing price by subtracting the Performance Clearing Price from the Total Regulation Clearing Price (the "Capability Clearing Price").[33]

Importantly, *each* resource that provides regulation will receive a payment for capability equal to the Capability Clearing Price times the cleared capability megawatts ("Capability Payment")[34] and a payment for performance equal to the Performance Clearing Price times the cleared capability megawatts ("Performance Payment").[35] Paying to *each* cleared resource the Capability Clearing Price, which includes the marginal resource's lost opportunity costs described in step one, satisfies the Commission's directive to pay all cleared frequency regulation resources a uniform clearing price that includes the marginal resource's opportunity costs.

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[30] *See* § II(A)(4)(b) below for description of the accuracy-adjusted Regulation capacity offer and accuracy-adjusted Regulation capacity offer. PJM proposes to adjust a resource's capability and performance offer based on the resource's historical accuracy of providing Regulation service in response to PJM's dispatch signal that will be used to adjust the resource's Regulation capability offers and performance offers. PJM will increase the cost to provide service in a resource's offer if such resource historically performs poorly. The increased cost of providing service will decrease the likelihood of being chosen have in the Regulation market-clearing process.

[31] Operating Agreement, Schedule 1, proposed § 3.2.2(c) of the Market-based Pricing Option and Administrative Pricing Option.

[32] Operating Agreement, Schedule 1, proposed § 3.2.2(c) and (f) of the Market-based Pricing Option and Administrative Pricing Option.

[33] Operating Agreement, Schedule 1, proposed § 3.2.2(c) and (g) of the Market-based Pricing Option and Administrative Pricing Option.

[34] Operating Agreement, Schedule 1, proposed § 3.2.2(g) of the Market-based Pricing Option and Administrative Pricing Option. In addition to the Capacity Payment, each resource shall be paid a Performance Payment, which is described in § II(A)(4) below.

[35] Operating Agreement, Schedule 1, proposed § 3.2.2(f) of the Market-based Pricing Option and Administrative Cap Option.

In addition, PJM is revising its Operating Agreement and Tariff to eliminate the Make-whole Payment, and thereby ensure a uniform payment to regulation resources, as required by Order No. 755. Specifically, PJM proposes to: (1) revise section 3.2.2(b)[36] of Schedule 1 of the Operating Agreement to eliminate the Make-whole Payment language providing resources "the higher of (i) the Regulation market-clearing price in such Regulation Zone or (ii) the sum of the regulation offer and the unit-specific opportunity cost of the generation resource supplying the increment of Regulation"[37]; (2) delete section 3.2.2(e) of Schedule 1 of the Operating Agreement to eliminate the instructions for providing resources with Make-whole Payments; and (3) revise its Tariff and Operating agreement to incorporate the joint optimization and pricing of energy, regulation, and reserves every five minutes[38] and, therefore, ensure that the regulation market-clearing price completely covers all committed resources' regulation offers (i.e., eliminating the need for the Make-whole Payments).[39]

b) Market-Based Payment

Order No. 755 further requires that capacity (capability) payments are market-based, and not administratively-determined.[40] To be market-based, such payments must be derived from the RTO's market-participant offers for the provision of frequency regulation capability.[41]

As described in the previous section, PJM proposes to modify its market rules and regulation market-clearing process to:

(1) utilize a resource's accuracy-adjusted capability offer, and accuracy-adjusted performance offer,[42] among other factors, to determine the incremental total cost for each resource in the ranking and clearing process with the highest

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[36] Operating Agreement, Schedule 1, proposed § 3.2.2(b) of the Market-based Pricing Option and Administrative Pricing Option.

[37] Operating Agreement, Schedule 1, § 3.2.2(b) of the Market-based Pricing Option and Administrative Pricing Option.

[38] PJM's joint optimization proposals are similar to the shortage-pricing rules approved by the Commission for ISO-New England, Inc. ("ISO-NE") and the New York Independent System Operator, Inc. ("NYISO"). *See New York Independent System Operator, Inc*., 129 FERC ¶ 61,164, PP 45-50 (2009); *ISO-New England, Inc.*, 130 FERC ¶ 61,054, PP 74-89 (2010).

[39] *See* § III below for a description of the proposed options to implement the Make-whole Payment.

[40] Order No. 755 at ¶99.

[41] *Id*.

[42] *See* § II(A)(4)(b) below for description of the accuracy-adjusted capacity offer and accuracy-adjusted performance offer.

ranked resource that clears setting the Total Regulation Market-clearing Price;[43]

(2) calculate the Performance Clearing Price based on the highest adjusted performance offer of the resources that cleared in step one;[44] and

(3) calculate the Capability Clearing Price by subtracting the Performance Clearing Price from the Total Regulation Market-clearing Price.[45] Each resource that provides regulation will be paid the Capability Payment and Performance Payment.[46]

This Capability Clearing Price and Capability Payment are ultimately derived from the market participants' offers from step one and, therefore, are market-based as required by Order No. 755.

c) Cross Product Opportunity Costs

Order No. 755 requires each RTO to (i) calculate each resource's cross-product opportunity costs (i.e., the foregone opportunity to participate in the energy or ancillary services markets); (ii) include the cross-product opportunity costs in each resource's offer to supply frequency regulation capacity; and (iii) use the cross-product opportunity costs to determine which resources clear and the market-clearing price.[47] Specifically, each RTO must include a resource's cross-product opportunity costs in the resource's offer to supply frequency regulation capacity to be used to determine the market-clearing resources and price.[48]

Section 1.11.4(b) of Schedule 1 of the Operating Agreement and its proposed revisions thereto satisfy this directive by requiring that PJM select the regulation resources that clear on the basis of: (1) each resource's regulation offer and the estimated opportunity cost of the resource providing regulation service as calculated by PJM; and (2) in accordance with PJM's obligation to minimize the total cost of energy, operating reserves, regulation, and other ancillary services. PJM estimates each offeror's opportunity costs on the basis of the expected value of the energy sales that would be foregone or uneconomic energy that would be produced by the resource in order to

[43]Operating Agreement, Schedule 1, proposed § 3.2.2(c) of the Market-based Pricing Option and Administrative Pricing Option.

[44]Operating Agreement, Schedule 1, proposed § 3.2.2(c) and (f) of the Market-based Pricing Option and Administrative Pricing Option.

[45]Operating Agreement, Schedule 1, proposed § 3.2.2(c) and (g) of the Market-based Pricing Option and Administrative Pricing Option.

[46]Operating Agreement, Schedule 1, proposed § 3.2.2(g) and (f) of the Market-based Pricing Option and Administrative Pricing Option.

[47] Order No. 755 at ¶102.

[48] *Id.*

provide regulation. Moreover, the proposed Total Regulation Market-clearing Price established for each hour includes the highest sum (from among the selected units) of a resource's accuracy-adjusted capability offer, accuracy-adjusted performance offer, and estimated opportunity costs.[49] Importantly, section 1.11.4 will continue to apply to the market rules proposed herein.

d) Inter-temporal Opportunity Costs

The Commission directed each RTO to allow a resource to include its inter-temporal opportunity costs in its offer to sell frequency regulation service, provided such costs are verifiable.[50] Each RTO is required to identify the party responsible for calculating such costs, whether the RTO itself or market participants.[51] According to the Commission: "An inter-temporal opportunity cost represents the foregone value when a resource must operate at one time, and therefore must either forego a profit from selling energy at a later time or incur costs due to consuming at a later time."[52] The trade-off presented to thermal storage provides an example of such costs. A thermal storage operator would prefer to "charge" (i.e., heat bricks or freeze water) when energy prices are low. If such a resource were to provide frequency regulation, it could be asked to stop charging during low price periods and then be forced to charge during high price periods.

As provided in PJM's manuals, PJM currently calculates inter-temporal opportunity costs for hydropower units only and includes such costs in a hydropower unit's offer to sell frequency regulation service.[53] The inter-temporal opportunity costs are calculated by averaging the historical price of energy for both on-peak and off-peak hours based on historical prices.[54] PJM utilizes the averaged set of on-peak and off-peak energy prices to estimate a hydropower unit's lost opportunity costs (i.e., to estimate the cost to that hydropower unit providing energy in other hours), which are included in a resource's offer to sell frequency regulation service.[55]

PJM proposes to revise its Tariff and Operating Agreement to allow PJM to calculate inter-temporal opportunity costs for inclusion in any resource's offer to sell frequency regulation service. Specifically, PJM proposes to add new section 3.2.2(h) to Schedule 1 of the Operating Agreement to require that PJM: "(i) calculate inter-temporal opportunity costs for each applicable resource; (ii) include such inter-temporal

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[49] Operating Agreement, Schedule 1, proposed § 3.22(c) of the Market-based Pricing Option and Administrative Pricing Option.

[50] Order No. 755 at ¶ 102.

[51] Order No. 755 at ¶ 103.

[52] Order No. 755 at n. 124.

[53] *See* § 3.2.8 (*Hydro Units*) of Manual 11 (*Energy & Ancillary Services*).

[54] *Id.*

[55] *Id.*

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" for each applicable resource in accordance with the PJM manuals.[56] Under these revised market rules, the owner of a resource may request that PJM create a process to calculate inter-temporal opportunity costs for the owner's class of resource, at which point the mechanism for calculating and verifying such costs will be developed through the PJM stakeholder process.

e) Charge State

In Order No. 755, the Commission required that each RTO and ISO address whether certain circumstances exist under which certain resources would not receive a Capability Payment.[57] The Commission provided the example of whether a storage resource, such as a battery, should "be eligible for a capacity payment during the time it charges in order to attain a charge state that allows it to provide frequency regulation service."[58] The Commission recognized that some RTOs and ISOs "manage the charge state of energy storage resources, while others do not… and found that it is appropriate to allow the RTOs and ISOs flexibility in addressing this issue and explaining any implications for compensation."[59]

As described above, PJM proposes a resource-neutral approach that provides both a Capability Payment and Performance Payment to *all* resources, including batteries, that are assigned regulation and provide adequate response to the regulation control signals.[60] In the event that a resource cannot or does not provide adequate response due to insufficient energy, the hourly score for accuracy, which is described further below,[61] for that resource will decrease, which will reduce the compensation for that resource for that market hour.[62] The likelihood of an energy-limited resource, such as a battery, encountering this situation is significantly reduced for resources that follow PJM's energy-neutral dynamic regulation signal.[63] This signal allows the resource owner to manage the state of charge with a high degree of confidence which ultimately increases the availability of such resources.

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[56] Operating Agreement, Schedule 1, proposed § 3.2.2(h) of the Market-based Pricing Option and Administrative Pricing Option.

[57] Order No. 755 at ¶ 100.

[58] *Id*.

[59] *Id*.

[60] Operating Agreement, Schedule 1, proposed § 3.2.2(f) and (g) of the Market-based Pricing Option and Administrative Pricing Option.

[61] *See* § II(A)(4)(e) below for a description of the Accuracy Score.

[62] Operating Agreement, Schedule 1, proposed § 3.2.2(f) and (g) of the Market-based Pricing Option and Administrative Pricing Option.

[63] *See* § 4.4.2 (*Regulation Signals*) of Manual 12 (*Balancing Operations*).

4. Performance Payment

The Commission required that the second part of the Two-Part Payment "be a performance payment that reflects the amount of work each resource performs in real-time."[64] Specifically, the Performance Payment must: (i) be market-based (i.e., this price must reflect the offers submitted by resources for the provision of frequency regulation service);[65] (ii) be paid uniformly to all resources cleared during the same settlement period;[66] (iii) be measured based on the absolute amount of regulation up and regulation down it provides in response to the system operator's dispatch signal;[67] and (iv) "account for the frequency regulation resources' accuracy in following the AGC dispatch signal when determining the performance payment compensation."[68]

a) Two-part Offers

In Order No. 755, FERC required RTOs and ISOs to implement two-part offers (i.e., a capacity offer and performance offer).[69] The Commission did not mandate specific parameters for such offers.[70]

Currently, resources offering frequency regulation into the PJM regulation Market must submit capability offers only. To satisfy the Commission's directive to implement a two-part offer mechanism, PJM is revising section 1.10.1A(e) of Schedule 1 of the Operating Agreement to: (1) require that each resource offering to provide frequency regulation submit a performance offer in dollars per change in megawatt, and (2) differentiate between the currently-required capacity offer and the newly-required performance offer, and (3) clarify that the "adder of up to $12.00 per megawatt of Regulation" in section 1.10.1A(e) that currently applies to the capability offers will apply to capability offers only under the proposed rules herein ("adder of up to $12.00 per megawatt of Regulation").[71] Moreover, PJM modified section 3.2.1 of Manual 11[72] to require a regulation resource to submit a performance offer in dollars in per change in megawatt for a particular hour, in addition to the capability offer that regulation resources currently must provide.

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[64] Order No. 755 at ¶ 199.

[65] Order No. 755 at ¶ 128.

[66] Order No. 755 at ¶ 131.

[67] Order No. 755 at ¶ 133.

[68] Order No. 755 at ¶ 153.

[69] Order No. 755 at ¶ 130.

[70] *Id.*

[71] Operating Agreement, Schedule 1, proposed § 1.10.1A(e) of the Market-based Pricing Option and Administrative Pricing Option.

[72] Proposed §§ 3.1, 3.2.1, 3.2.6, and 3.2.7 of Manual 11 (*Energy and Ancillary Services Market Operations*). Revisions in manuals marked proposed are not yet effective. *See* at http://www.pjm.com/committees-and-groups/task-forces/rpstf.aspx#3.

b) Market-based Performance Payment

Order No. 755 also requires that the Performance Payment be market-based.[73] Specifically, the price must reflect the market participant offers submitted by resources for the provision of frequency regulation service.[74]

Currently, PJM does not consider any potential variation in the requested movement for a resource or the accuracy of that resource in its market clearing process. Rather, PJM's market-clearing process ranks the regulation resources in the order of cost based on the sum of a resource's opportunity costs and offers for capacity.[75] The highest ranked resource that clears is the marginal unit that sets the price for an hour.[76] Each resource is paid the clearing price times the amount of regulation (megawatts) provided.[77] Importantly, PJM does not consider a resource's performance in today's market clearing process.

PJM proposes to revise its market rules and manuals to provide a market-based Performance Payment to resources that provide Regulation. PJM proposes to revise section 3.2.7 of Manual 11 (*Energy & Ancillary Services Market Operations*) to adjust each resource's capability offer and performance offer by that resource's historic accuracy scores.[78] Specifically, under PJM's proposed rules, PJM will: (1) adjust a performance offer and capability offer based on the benefit factor[79] to reflect that a fast-following resource will provide more benefits to system control for the same amount of regulating capacity;[80] and (2) calculate an accuracy score based on a resource's historic performance to adjust each resource's performance offer and capability offer. This average accuracy score for each resource will be based on a resource's accuracy while providing regulation service averaged over a rolling one hundred hours.[81] For each new regulation resource that has not yet provided one hundred hours of regulation service under the accuracy scoring system, PJM will create an average accuracy score based on a pro-rata ratio of a resource's actual accuracy score and the resource's accuracy score

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[73] Order No. 755 at ¶ 128.

[74] Order No. 755 at ¶ 199.

[75] Operating Agreement, Schedule 1, § 3.2.2(c).

[76] Operating Agreement, Schedule 1, § 3.2.2(c).

[77] Operating Agreement, Schedule 1, § 3.2.2(b).

[78] *See* II(A)(4)(e) for a description of the accuracy score calculation.

[79] *See* II(A)(2) for a description of the benefit factor.

[80] Operating Agreement, Schedule 1, proposed § 3.2.2(f) of Market-based Pricing Option and Administrative Cap Option.

[81] PJM will calculate a separate average accuracy score for the traditional regulation signal and dynamic regulation signal for a resource that follows both signals. The average accuracy score traditional regulation signal and dynamic regulation signal will be based on, respectively, the traditional regulation signal only and dynamic regulation signal only.

achieved during PJM's regulation qualification process.[82] PJM proposes to utilize the average-accuracy score to adjust the resource's position in the merit order stack.[83] This adjustment appropriately results in an increased cost of poorer performing resources in PJM's market-clearing and pricing algorithms and, therefore, a decreased probability of clearing during the regulation market-clearing process. In other words, each resource gets valued in the merit order stack based on both the cost of the submitted bids and the benefits that resource is expected to provide to system control.

To ensure that the Performance Payment is market-based, PJM proposes to revise section 3.2.2 of Schedule 1 of the Operating Agreement to: (1) include a resource's accuracy-adjusted capability offer, accuracy-adjusted performance offer, and lost opportunity costs when determining the incremental total cost for each resource in the ranking and clearing process with the highest ranked resource that clears determining the Total Regulation Market-clearing Price;[84] (2) calculate a specific performance regulation clearing price based on the highest adjusted performance offer of the resources that cleared in step one Performance Clearing Price);[85] and (3) calculate the Performance Payment based on the requested megawatt movement and the resource's response to the regulation control signal.[86] Each resource that provides regulation shall be paid a Performance Payment.[87] The Performance Payment will be market-based because it will be derived from market-participants' offers to supply frequency regulation capacity (i.e., the performance offers are used, among other inputs, to determine the resources that clear in the market and to set the Performance Market Clearing Price).

c) Performance Payment for the Absolute Amount of Regulation Up and Regulation Down

In Order No. 755, the Commission required the second part of the Two-Part Payment be a Performance Payment that "reflects the amount of work each resource performs in real-time."[88] Specifically, the Commission stated that: "A resource's performance must be measured based on the absolute amount of regulation up and regulation down it provides in response to the system operator's dispatch signal."[89]

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[82] Manual 12 describes the regulation qualification process. A seventy-five percent compliance rating is the qualification score a resource must achieve to qualify to provide regulation.

[83] Proposed § 3.2.7 of Manual 11 (*Energy and Ancillary Services Market Operations*).

[84] Operating Agreement, Schedule 1, proposed § 3.2.2(c) of the Market-based Pricing Option and Administrative Pricing Option.

[85] Operating Agreement, Schedule 1, proposed § 3.2.2(c) and (f) of the Market-based Pricing Option and Administrative Pricing Option.

[86] Operating Agreement, Schedule 1, proposed § 3.2.2(f) of Market-based Pricing Option and Administrative Cap Option.

[87] *Id.*

[88] Order No. 755 at ¶ 199.

[89] Order No. 755 at ¶ 133.

PJM proposes to meet this directive by modifying section 3.2.2 of Schedule 1 of the Operating Agreement to require each resource to submit a performance offer and adjusting such offers as described in the previous section.[90] The proposed rules will incorporate such adjusted offers into its market-clearing process to produce the Performance Regulation Market-clearing Price that each regulation resource receives.[91] To acknowledge the greater amount of frequency regulation service being provided by high performing resources, PJM proposes to further modify section 3.2.2 and the relevant provisions of the PJM Manuals to compensate a regulation resource for the absolute amount of the megawatt movement for regulation that the resource provides. In other words, resources will be compensated for the total increases and decrease in injections or withdrawals of real power. Specifically, PJM will send a dispatch signal to a regulation resource every two seconds,[92] measure the regulation resource's response to the dispatch signal every ten seconds[93] and compensate the resource for the total megawatt amount of regulation up and down multiplied by the accuracy score described below.[94]

d) Uniform Performance Price

The Commission also required "that the clearing performance price be paid uniformly paid to all resources cleared during the same settlement period"[95] because "[a] uniform clearing price sends an efficient price signal to all current and potential market participants."[96] PJM proposes to revise section 3.2.2 (c) and (f) of Schedule 1 of the Operating Agreement to calculate the Performance Clearing Price on a five-minute interval and pay the owner of *each* resource that provides regulation service during an hour Performance Payment calculated using the average of the five-minute Performance Regulation Market-clearing Prices for the hour, thereby satisfying the Commission's directive to pay the clearing performance price uniformly to all resources cleared during the same settlement period.[97]

e) Measurement of a Resource's Accuracy to the Dispatch Signal

Additionally, the Commission found "that measuring and accounting for accuracy in a resource's compensation is just and reasonable and will encourage resources to

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[90] Operating Agreement, Schedule 1, proposed § 3.2.2(f) of the Market-based Pricing Option and Administrative Cap Option.

[91] *Id*.

[92] § 4.4.2 (*Regulation Signals*) of Manual 12.

[93] *Id*.

[94] Proposed § 4.2 (*Regulation Credits*) of Manual 28 (*Operating Agreement Accounting*).

[95] Order No. 755 at ¶ 131.

[96] *Id*.

[97] Operating Agreement, Schedule 1, proposed § 3.2.2(f) of the Market-based Pricing Option and Administrative Cap Option.

report accurately their achievable ramp rate and to follow the system operator's dispatch instructions."[98] Therefore, the Commission mandated that each RTO "account for frequency regulation resources' accuracy in following the dispatch signal when determining the performance payment compensation."[99]

To satisfy the directive that RTOs measure each resource's accuracy, PJM proposes to revise its market rules and manuals to create an accuracy score that is based upon PJM's measurement of a regulation resource's response to the dispatch signal (the "Accuracy Score").[100] The Accuracy Score may range from zero to one with the highest score being achieved by following exactly the regulation control signal within a ten-second delay allowed for signal propagation. PJM will telemetrically distribute PJM's dispatch signal ("Regulation Dispatch Signal") to a regulation resource and measure the regulation resource's response to the Regulation Dispatch Signal via a response signal sent to PJM by the regulation resources every two seconds (the "Regulation Response Signal").[101] Based on these measurements, PJM will calculate an Accuracy Score for a regulation resource for each ten-second interval that is composed of three factors: (a) the difference in the energy requested by PJM via the Regulation Dispatch Signal and the energy provided by a Regulation Response Signal (the "Energy Score"); (b) the delay in time between the Regulation Dispatch Signal and Regulation Response Signal (the "Delay Score"); and (c) the correlation between the Regulation Dispatch Signal and Regulation Response Signal (the "Correlation Score").[102] Each of the three components of the Accuracy Score represents an important metric to determine if a regulation resource has accurately responded to PJM's dispatch signal. This score is designed to create an objective standard for the benefit that a resource's regulation response provides to system control. Therefore, it does not provide special consideration for the response characteristics of classes of resources or other similar exceptions. Instead, it uses a single scoring method for all resources.

Moreover, to account for accuracy in a resource's compensation PJM proposes to revise section 3.2.2(f) of Schedule 1 of the Operating Agreement to base the Performance Payment on, among other factors, "the accuracy with which each resource responds to the PJM's Regulation signals during the hour."[103] PJM will also make confirming modifications to section 4 (*Regulating Accounting*) of PJM Manual 28 (*Operating Agreement Accounting*) to base the Performance Payment on the Accuracy Score.

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[98] Order No. 755 at ¶ 151.

[99] Order No. 755 at ¶ 153.

[100] *See* Operating Agreement, Schedule 1, proposed §§ 1.7.18(e) and 3.2.2(f) of the Market-based Pricing Option and Administrative Cap Option. *See also* proposed §§4.4.2 and 4.5.6 of Manual 12 (*Balancing Operations*) at http://www.pjm.com/committees-and-groups/task-forces/rpstf.aspx#3.

[101] *See* proposed §§4.4.2 and 4.5.6 of Manual 12 (*Balancing Operations*).

[102] *Id*.

[103] Operating Agreement, Schedule 1, proposed § 3.2.2(f) of the Market-based Pricing Option and Administrative Cap Option.

B. Market-power Mitigation

In Order No. 755, the Commission determined that RTOs and ISOs would need to make fundamental changes to the manner in which they "procure and compensate frequency regulation resources, which may render existing RTO and ISO market power rules insufficient for purposes of addressing market power concerns."[104] Therefore, the Commission required each RTO and ISO "either to submit tariff provisions for market power mitigation methods appropriate to redesigned frequency regulation markets or to explain how their current mitigation methods are sufficient to address market power concerns given the changes required in this rulemaking."[105]

PJM currently utilizes the TPS Test to determine if structural market power exists in the regulation market.[106] The TPS Test adds the regulation capability of a supplier to the regulation capability of the two largest suppliers in the regulation market.[107] If that total regulation capability is greater than the surplus of total regulation capability exceeding the Regulation requirement then the supplier would fail the test and be subject to mitigation.[108] PJM defines available supply for purposes of the market structure screen as all offers submitted at a total cost (cost-based offer plus opportunity cost) less than or equal to one hundred and fifty percent of the cost-based clearing price.[109]

PJM proposes to modify section 3.2.2A.1 of Schedule 1 of the Operating Agreement to incorporate the performance offer when calculating the total cost for its TPS Test.[110] Specifically, PJM proposes to modify the components of total cost in the definition of available supply to (1) clarify that the cost-based offer currently in the total cost is the adjusted capacity cost-based offer and (2) include the adjusted performance cost-based offer in the total price.[111] The proposed revisions to include the performance cost-based offer in the definition of available supply in the TPS Test described herein is essentially the same as the TPS Test currently employed for the regulation market. Moreover, such revisions to total cost correspond to revisions described above to include performance offers in the process to determine regulation market clearing prices to which the total cost is compared when determining the available supply. Finally, increasing the amount of regulation offered, as the effect of the market rule revisions contained herein

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[104] Order No. 755 at ¶ 136.

[105] Order No. 755 at ¶ 136.

[106] Operating Agreement, Schedule 1, § 3.2.2A.

[107] Operating Agreement, Schedule 1, § 3.2.2A.1(a).

[108] Operating Agreement, Schedule 1, §§ 3.2.2(c) and 3.2.2A.1(a).

[109] Operating Agreement, Schedule 1, § 3.2.2A.1(b)(i).

[110] Operating Agreement, Schedule 1, proposed § 3.2.2A.1 of the Market-based Pricing Option and Administrative Cap Option.

[111] Operating Agreement, Schedule 1, proposed § 3.2.2A.1(b)(i) of the Market-based Pricing Option and Administrative Cap Option.

are likely to do, can only increase the market's competitiveness and thereby decrease the occasions when implementation of market power mitigation will be necessary.

C. Miscellaneous Revisions to the Operating Agreement and Tariff

PJM includes certain miscellaneous clean up revisions to Schedule 3 of the Tariff and Schedule 1 of the Operating Agreement unrelated to PJM's compliance with Order No. 755. The revisions are included in chart of revisions in Attachment A. Specifically, in Schedule 3, PJM proposes to revise references to "procedures of the Office of the Interconnection" to "PJM Manuals" for clarity. Moreover, PJM proposes to revise 1.7.18(c) of its market rules to specify the location of information pertaining to the resources regulation range.

PJM also proposes to modify Section 3.2.2 of Schedule 1 of the Operating Agreement to clarify that each Internal Market Buyer's pro rata share of the regulation requirements is based on its total load. Specifically, in section 3.2.2(a), PJM proposes to revise "Market Buyer's total load" to read "Internal Market Buyer's total load."

III. RELATIONSHIP BETWEEN PJM'S ORDER NO. 719 COMPLIANCE FILING AND ORDER NO. 755 DIRECTIVES

A. Issues Caused by Make-Whole Payments

In Order No. 755, the Commission noted that PJM's practice of estimating opportunity costs during its ex-ante regulation market-clearing process and subsequently providing an after the fact payment to individual units based on actual opportunity costs may be unduly discriminatory because such payments are not reflected in the uniform market clearing price calculation.[112] Therefore, PJM's compliance with the following directives in Order No. 755 requires the elimination of the Make-whole Payment: (1) payment "to all cleared frequency regulation resources a uniform clearing price that includes the marginal resource's opportunity costs" as part of the Capability Payment;[113] (2) ensuring the Capability Payment is "based on competitive market-based offers for the provision of frequency regulation capacity submitted by resources;"[114] (3) ensuring "that the clearing performance price be paid uniformly to all resources cleared during the same settlement period;"[115] and (4) ensuring that "[t]he performance payment must be market-based."[116] Providing compensation to Regulation resources via after-the-fact Make-whole Payments, as PJM presently does, fails to satisfy the above requirements because the Make-whole Payments would result in non-uniform payments to resources that received such after-the-fact payments. Further, such payments would not be based on a

[112] Order No. 755 at ¶ 18.

[113] Order No. 755 at ¶ 99.

[114] Order No. 755 at ¶ 197.

[115] Order No. 755 at ¶ 131.

[116] Order No. 755 at ¶ 199.

uniform clearing price based on the competitive market-based offers of all resources, but rather based on the individual offer of the resource to which the Make-whole Payment is provided. Make-whole Payments result in the potential to dispatch "a unit with relatively low explicit capacity costs but very high opportunity costs, rather than a lower-cost unit which has relatively higher explicit capacity costs but low opportunity costs. This can result in distorted investment and entry decisions by market participants,"[117] such as flywheels and batteries. The Commission noted that "[t]his problem is especially glaring in a market such as this where some resources have no opportunity costs, resulting in disparate payments to resources."[118] Providing a uniform clearing price "will ensure that all appropriate costs are considered and will send an efficient price signal to current and potential market participants."[119] Therefore, in order to meet the Commission's requirements noted above, PJM now proposes to eliminate such after-the-fact Make-whole Payment in its market rules.

B. Five-Minute Joint Optimization and Pricing of Energy, Reserves, and Regulation in Order No. 719 Compliance Filing Required to Eliminate Make-whole Payments

Furthermore, the joint optimization proposal pending in PJM's Order No. 719 Compliance Filing submitted on June 18, 2010 in Docket No. ER09-1063-000[120] is required to eliminate the Make-whole Payments because PJM must address the uncertainty of estimated system conditions caused by its existing market rules. Make-whole Payments under PJM's current market rules are required because PJM calculates the Regulation market clearing price at the same time it commits regulation resources, up to an hour before the resources provide regulation service. Commitment of resources sufficiently ahead of the timeframe for which they provide regulation service ensures that resource owners have sufficient time to position their resource to regulate in the upcoming hour. However, calculation of the clearing price at the time the commitment is accomplished was a market design decision adopted when the PJM regulation market was initially implemented given the state of technology at the time. This ex-ante clearing price calculation process requires an estimation of the upcoming market conditions which often differ from the actual conditions that later occur. Such differences may increase the lost opportunity cost for resources committed for regulation. These increased lost opportunity costs are not captured in the regulation market clearing price because the calculated price is currently based on the estimated lost opportunity costs determined during the hour-ahead clearing process. Additionally, as described more completely in the Order No. 719 Compliance Filing,[121] the Make-whole Payment may be required to properly compensate a regulation resource that failed to clear in the hour-ahead

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[117] Order No. 755 at ¶ 99.

[118] Order No. 755 at ¶ 79.

[119] Order No. 755 at ¶ 99.

[120] Need to cite to the filing here ("Order No. 719 Compliance Filing").

[121] Order No. 719 Compliance Filing at pp. 26 – 28.

regulation market-clearing process but which PJM subsequently assigned to provide regulation in real-time because actual system conditions deviated from the hour-ahead forecasted system conditions utilized to clear the market. [122]

Therefore, to eliminate the Make-whole Payments as required in Order No. 755, among other benefits described below, PJM must eliminate the uncertainty of estimated system conditions by jointly optimizing and pricing energy, reserves, and regulation on a five-minute basis using actual system conditions. Such joint optimization market rule changes were included in PJM's Order No. 719 Compliance Filing.

In this Order No. 755 compliance filing, PJM proposes two alternative options to implement the joint optimization components in the Order No. 719 Compliance Filing. The first option, the Market-based Pricing Option, proposes to implement the revisions proposed in section III above and key aspects of the pending Order No. 719 Compliance Filing proposed Tariff and Operating Agreement revisions, including the joint optimization components.[123] The second option, the Administrative Cap Option, proposes to implement the revisions proposed in section III above and a more limited set of Tariff and Operating Agreement revisions from the Order No. 719 Compliance Filing that are necessary to implement PJM's joint optimization of the energy and ancillary services markets and, substitute an administrative process which would substantially, but not entirely, eliminate Make-whole Payments under the Tariff and Operating Agreement. The pros and cons of each approach are described below.

C. Market-based Pricing Option Versus Administrative Cap Option

1. Market-based Pricing Option

To implement the Order No. 755 compliance market rule revisions under the Market-based Pricing Option, PJM respectfully requests that the Commission approve the revisions identified in section III above and all of the pending market rule revisions in PJM's Order No. 719 Compliance Filing. Approval of all the changes PJM filed in compliance with Order No. 719 would result in accurate pricing of energy and reserves both in normal system conditions as well as shortage conditions, and eliminate, as the Commission required, Make-whole Payments to resources providing reserve products under all these conditions.[124]

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[122] Forecasted system conditions include, but are not limited to, load, interchange, and resource performance.

[123] As noted herein, the Commission could, under the Market Based Pricing Option or the Administrative Cost Option hold certain aspects of PJM's Order 719 compliance filing for further review.

[124] In the Order No. 719 Compliance Filing, PJM proposes a four-year transition period to phase in the reserve penalty factors. Under such approach, the reserve penalty factors gradually rise over four years until they reach the steady-state price of $850 per megawatt-hour. Under the Market-based Pricing Option, PJM will completely eliminate the Make-whole Payments, and therefore satisfy the Commission's directives in Order No. 755, once it reaches the reserve penalty factor of $850 per

a) Market-based Pricing Option with Phase 1 Penalty Factors

In view of the disadvantages associated with the Administrative Cap Option, PJM has considered alternatives under the preferred Market-based Option. PJM believes one potential alternative under this option is for the Commission to approve the majority of PJM's Order No. 719 Compliance Filing changes while deferring acceptance of three of the four years in the penalty factor transition that was proposed in that filing. The Commission could accept for the time being only the first phase in the four-year transition plan, whereby only the lowest set of penalty factors would be applied through the reserve demand curves.[125] The impact of this alternative would mean that the PJM's automated software would not assign any reserves during a shortage condition for which the cost was in excess of this lowest reserve penalty factor. If, however, in order to meet operating reliability compliance requirements, PJM dispatchers were to manually assign units to provide reserve products that had a cost that was higher than this lowest possible penalty factor, a Make-whole Payment would be necessary to protect such manually assigned units from lose because calculated opportunity costs would be greater than the penalty factor price that would result. As illustrated in the above examples, opportunity cost would be greater than the penalty factor price that would result.

PJM proposes this compromise as one that is still preferable to the Administrative Cap Option. While it retains the potential for Make-whole Payment, as noted above, PJM believes the incidents that would trigger such out-of-market payments would be sufficiently few so that the challenges and inefficiencies associated therewith would be tolerable and still meet the Commission's Order No. 755 compliance requirements.

2. Administrative Cap Option

To implement the Order No. 755 compliance market rule revisions under the Administrative Cap Option, PJM proposes to revise its market rules as proposed in section III above and to incorporate only the *subset* of the market rule revisions in Order No. 719[126] that are absolutely necessary to effectuate the joint optimization and pricing of energy, regulation, and reserves every five minutes.[127] As described in more detail below,

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megawatt-hour in the fourth year of the four-year transition plan. *See* Order No. 719 Compliance Filing at PP 32-33.

[125] This alternative Market-based Pricing Option may be inconsistent with one of the Commission's directives in Order No. 719. Specifically, the Commission allowed RTOs to phase in any new pricing rules for a period of a few years, "*provided that transition period was not protracted.* [Emphasis Added]." *See* Order No. 719 at ¶ 258. Specifically, allowing the reserve penalty factor to be set at $250 per megawatt-hour, the first phase of the four-year transition, indefinitely may contradict such directive.

[126] *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 73 Fed. Reg. 64,100, FERC Stats. & Regs. ¶ 31,281 (October 28, 2008) ("Order No. 719").

[127] Operating Agreement, Schedule 1, proposed §§ 2.2, 2.3, 2.5(a), 3.2.2(c), 3.2.3A(e), and 3.2.2(d) of the Administrative Cap Option. Attachment A contains the pending and proposed Tariff and Operating Agreement revisions for the Market-based Pricing Option and the proposed Tariff and Operating Agreement revisions for Administrative Cap Option. The Joint Optimization language from the Order

these revisions would eliminate the Make-whole Payments to regulation resources only during non-scarcity conditions. However, during periods when shortages of reserves or regulation are encountered, Make-whole Payments would still be necessary. This continuation of make-whole payments is not desirable, especially during reserve/regulation shortage conditions when the market depends upon accurate pricing to incent investment in innovative resources. Therefore, if PJM's Market-based Pricing Option is not accepted, and the Administrative Cap Option is implemented instead, then PJM proposes additional market rule revisions to integrate the joint optimization revisions[128] while leaving in place PJM's existing scarcity pricing rules in section 6A of Schedule 1 of the Operating Agreement, which scarcity pricing rules PJM proposed to eliminate in the Order No. 719 Compliance Filing.[129] PJM proposes these market rule revisions in recognition that, under the Administrative Cap Option, during scarcity conditions, energy and reserves can no longer be optimized and prices set accordingly under scarcity conditions without the reserve penalty factors proposed as part of the Order No. 719 Compliance Filing. Specifically, the reserve penalty factors proposed as part of the Order No. 719 Compliance Filing prevent the prices for reserves, including regulation, from decreasing as the availability of the products decreases during scarcity conditions, as described below in section III(C)(4). Therefore, under this Administrative Cap Option, PJM proposes to revise its market rules to hold the price of reserves and regulation constant for the duration of a synchronized reserve shortage at the last value before the start of a synchronized reserve shortage[130] and, therefore, add new section 3.2.2(i) to Schedule 1 of the Operating Agreement to provide resources with a Make-whole Payment when PJM is no longer able to meet its synchronized reserve requirement for a reserve region to ensure that regulation resources are properly compensated for all lost opportunity costs.

3. Pros and Cons of the Market-based Pricing Option and Administrative Cap Option

Both the Market-based Pricing Option and Administrative Cap Option contain the market rule revisions necessary to calculate a market-clearing price for energy, reserves, and regulation products every five minutes and eliminate the Make-whole Payments during periods when reserve shortages do not exist. However the Administrative Cap Option continues to result in suppression of regulation prices during times of reserve or

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No. 719 Compliance Filing is not marked as pending in the Administrative Cap Option because it is a subset of the language that is pending. *See* § VI (*Documents Enclosed*) below.

[128]Operating Agreement, Schedule 1, proposed §§ 2.2, 2.3, 2.5(a), 3.2.2(c), 3.2.3A(e), and 3.2.2(d) of the Administrative Cap Option.

[129]*See* Operating Agreement, Schedule 1, proposed §§ 2.5(b), 3.2.2(c), 3.2.2(i), and 3.2.3A(m) of Administrative Cap Option.

[130] Operating Agreement, Schedule 1, proposed §§ 3.2.2(c), 3.2.2(i), and 3.2.3A(m) of the Administrative Cap Option (respectively, revisions to hold the price of regulation constant, revisions to hold the price of regulation constant, and revisions to hold the price of reserves constant).

regulation shortages which can result in Make-whole payments and can undermine the effectiveness of FERC Order No. 755 compliance. The suppression of regulation prices during shortage conditions is a counterintuitive result which may stifle investment in innovative resources when the system needs them most. Therefore, the Market-based Pricing Option is PJM's preferred approach and PJM urges the Commission to approve the Market-based Pricing Option for the following reasons.

1) The Market-based Pricing Option appropriately prices energy, reserves and regulation during shortage conditions which in a market-clearing process that utilizes the most efficient set of resources to provide energy, reserves, and regulation under all conditions.

2) The Market-based Pricing Option allows PJM to completely eliminate the Make-whole Payment. In contrast, while substantially eliminating the Make-whole Payment, the Administrative Cap Option contains an exception for the Make-whole Payments.

3) The Administrative Cap Option is suboptimal because it requires PJM's system operators to answer additional calls from generation and demand response resource owners about inconsistent pricing and requires operators to switch to an alternative dispatch model and, therefore, an alternative set of dispatch tools during regulation and reserve shortages. The Administrative Cap Option requires an independent separate calculation of energy and reserve prices due to the administrative nature of the model, which each other. These inconsistent prices that result have in the past caused confusion and many burdensome phone call inquiry to PJM dispatchers with questions from asset owners regarding the validity and inconsistency of such prices. Moreover, the confusion and distraction administrative pricing rules caused by the Administrative Cap Option during emergency operating conditions by the, not to mention the result in additional manual dispatches by system operators and, therefore, additional work during emergency operations is undesirable.[131]

4) The Administrative Cap Option results in an administratively set price for regulation and reserves when during those times where PJM cannot meet its synchronized reserved requirements.[132] Such administratively set regulation and reserve prices result in the inefficient economic dispatch of frequency regulation resources; whereas, a "market-based price will better reflect current system conditions and need for frequency regulation, thereby providing market participants with an efficient price signal."[133] In other words, the Market-based Pricing Option results in a market-clearing process that: (1)

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[131] *See Affidavit of Adam J. Keech on Behalf of PJM Interconnection, L.L.C.*, PJM Director of Dispatch, System Operations attached hereto.

[132] Operating Agreement, Schedule 1, proposed § 3.2.2(e) of the Administrative Cap Option.

[133] Order No. 755 at ¶ 128.

utilizes the most efficient set of resources to provide energy, reserves and regulation at all prices for energy; and (2) regulation resources are properly compensated under all conditions using this approach.

5) Under the Administrative Cap Option, the price of reserves and regulation will be lower than they should be when these services are most needed on the grid. This result is counterproductive and could significantly reduce the effectiveness of FERC Order No. 755 in providing incentives for investment in alternative resources to provide grid services. .

6) Under the Administrative Cap Option, it is more difficult to determine to what extent prevailing energy or reserve prices are a result of the tight supply and demand conditions or potential exercises of market power in trying to maintain energy balance and some level of reserves. In contrast, the Market-based Pricing Option results in prices in the energy and ancillary markets gradually rising as resources become increasingly scarce, which should provide increased confidence that a rise in market prices is a result of tight supply and demand conditions and not potential exercises of market power.

7) Under PJM's current Tariff and Operating Agreement provisions, which continue to be effective under the Administrative Cap Option,[134] market-power mitigation is suspended when various emergency procedures are invoked such as the initiation of maximum emergency generation conditions, emergency purchases, voltage reductions, or a manual load dump. These emergency procedures are indicators of approaching or actual reserve shortage conditions. Suspending market power mitigation, as it is currently effective and as proposed in the Administrative Cap Option, are is not favored by the Commission and reduces market participants' confidence with respect to the finality and validity of market prices because it would be "difficult to discern during reserve shortage conditions to what extent prevailing energy or reserve prices are a result of the tight supply and demand conditions or potential exercises of market power in trying to maintain energy balance and some level of reserves."[135] Whereas in contrast, under the Market-based Pricing Option, prices in the Energy and Ancillary Service markets will gradually rise as resources become increasingly scarce.[136] This gradual rise should provide market participants with confidence that rise in market prices results from tight supply and demand conditions and not potential exercises of market power.

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[134] *See* Operating Agreement, Schedule 1, § 6A. *See also* Operating Agreement, Schedule 1, proposed § 6A of the Administrative Cap Option.

[135] Order No. 719 Compliance Filing at p. 41.

[136] Operating Agreement, Schedule 1, proposed § 3.2.2(e) of the Market-based Pricing Option.

4. Detailed Rationale for Make-whole Payments under the Administrative Cap Option

PJM proposes to revise its market rules to hold the price of reserves and regulation constant for the duration of a synchronized reserve shortage at the last value before the start of a synchronized reserve shortage.[137] PJM proposes those market rule revision in recognition that, under the Administrative Cap Option, energy and reserves can no longer be optimized and prices set accordingly under scarcity conditions without the reserve penalty factors proposed as part of the Order No. 719 Compliance Filing. The penalty factors prevent the prices for reserves, including regulation, from decreasing as the availability of these products reduces during scarcity conditions. Without such penalty factors, the decrease in the price of the reserve products would occur because, as the products became shorter under scarcity conditions, the opportunity cost of the marginal resource for these products would decrease as the resources with the greatest opportunity cost with respect to energy were assigned to provide energy instead of reserves.

The following example illustrates the rationale supporting this proposition. Suppose PJM is experiencing scarcity conditions and the energy price is $1,000 per megawatt-hour. Two resources are providing 50 megawatts of regulation each, one with an energy offer price of $100 per megawatt-hour and one with an energy offer price of $200 per megawatt-hour. The opportunity cost of foregone energy sales from providing regulation service experienced by the resource with the $100 per megawatt-hour energy offer price is $900 per megawatt-hour and the opportunity cost experienced by the resource with the $200 per megawatt-hour energy offer price is $800 per megawatt-hour. Assuming, for simplicity, that the regulation offer prices are $0 per megawatt-hour for both resources resulting in only their opportunity cost being included in the regulation market-clearing price (total cost equals offer plus opportunity cost), the resource with the $100 per megawatt-hour energy offer price would set the regulation market-clearing price with the $900 per megawatt-hour opportunity cost. This situation is depicted below in Figure B.

[137] Operating Agreement, Schedule 1, proposed §§ 3.2.2(c), 3.2.2(i), and 3.2.3A(m) of the Administrative Cap Option (respectively, revisions to hold the price of regulation constant, revisions to hold the price of regulation constant, and revisions to hold the price of reserves constant).

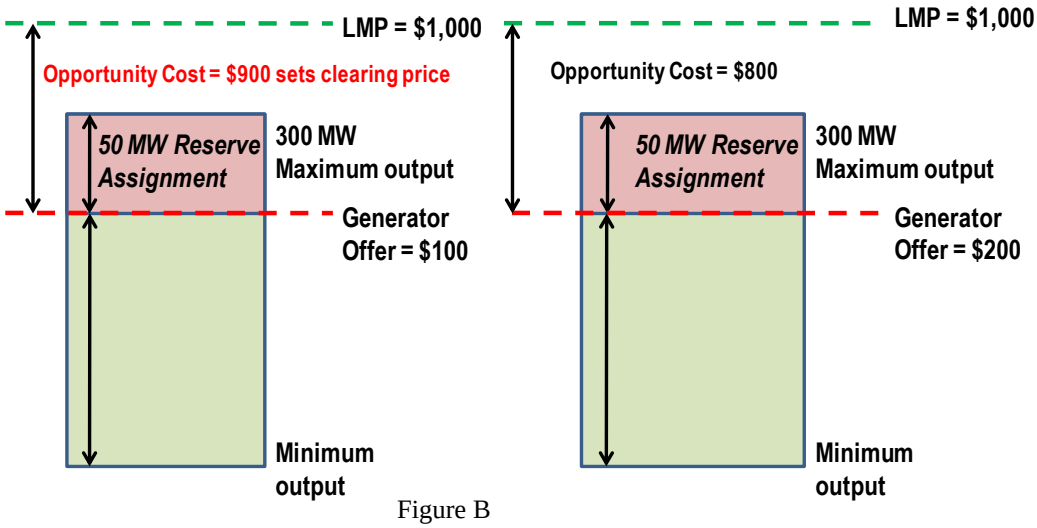

Figure B

If the PJM load increases by another 50 megawatts and PJM needs to convert one of the resources assigned to provide regulation service to instead provide energy, the resource with the lowest energy offer price will be converted first. Therefore, in this example, the resource with the $100 per megawatt-hour energy offer price will be converted to provide energy, and only the resource with the $200 per megawatt-hour energy offer price will be left providing regulation. As a result, the regulation market-clearing price would decrease to $800 per megawatt-hour, reflecting the opportunity cost of the remaining resource providing regulation service. This situation is depicted below in Figure C.

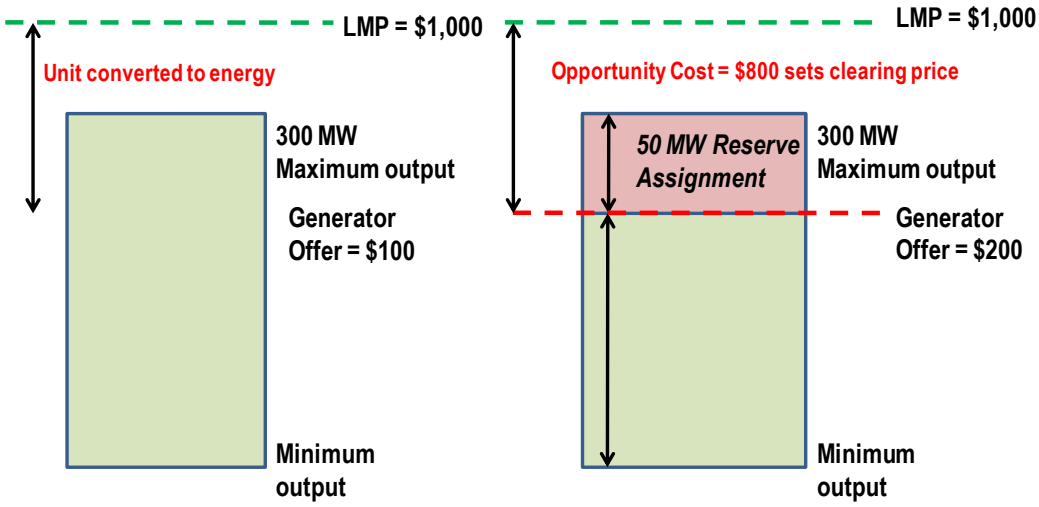

Figure C

Therefore, to prevent this counterproductive result under the Administrative Cap Option, PJM is revising its market rules to hold the price of reserves and regulation constant for the duration of a synchronized reserve shortage at the last value before start

of a synchronized reserve shortage.[138] This administrative cap on regulation and reserve prices will account for the fact that the low energy-offer cap prevents energy, reserves, and regulation from being jointly optimized beyond $1,000, and avoid the undesirable result of a continuous decrease in the prices of regulation and reserves the shorter these products became during reserve shortages. PJM proposes to revise its market rules to set the synchronized reserve shortage as a trigger to administratively set the prices for the three real-time products.[139] This trigger is appropriate because it is the last point at which all three products can properly be jointly optimized.

As evident from these examples, the Administrative Cap Option is a deficient and inefficient approach to addressing the elimination of Make-whole Payments because it sets a price cap that fails to reflect the true value of energy, reserves, and, importantly, regulation service during a shortage condition and results in the need for Make-whole Payments to resources in the reserve and regulation markets during such conditions. Consider the following, simple example of a unit that is reduced to provide a reserve product. As can be seen from Figure D below, this unit has a maximum output level of 300 megawatts. If the unit is reduced from that maximum output level to provide 50 megawatts of synchronized reserves or regulation, the unit will incur an opportunity cost equal to the quantity of foregone energy production (50 megawatts in this example) times the difference between the locational marginal price ("LMP") and the unit's offer price at the level to which it is reduced to provide reserves. In this example, the LMP is $350 per megawatt-hour prior to the initiation of Scarcity conditions and the unit's offer price $150 per megawatt-hour at the level to which it is dispatched to provide reserves. Therefore, the opportunity cost incurred is ($350 per megawatt-hour minus $150 per megawatt-hour) times (50 megawatt), which equals $10,000. Assuming this unit were the marginal unit for either synchronized reserve or regulation, and further, for simplicity, that the unit's offer price for the assigned reserve product was $0, the unit would set the price for the assigned product at its opportunity cost of $200 per megawatt-hour.

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[138] *See* Operating Agreement, Schedule 1, proposed §§ 2.5(b), 3.2.2(c), 3.2.2(i), and 3.2.3A(m) of Administrative Cap Option.

[139] Operating Agreement, Schedule 1, proposed §§ 3.2.2(c), 3.2.2(i), and 3.2.3A(m) of the Administrative Cap Option (respectively, revisions to hold the price of regulation constant, revisions to hold the price of regulation constant, and revisions to hold the price of reserve). However, the overall energy price cap of $1,000 will continue to apply.

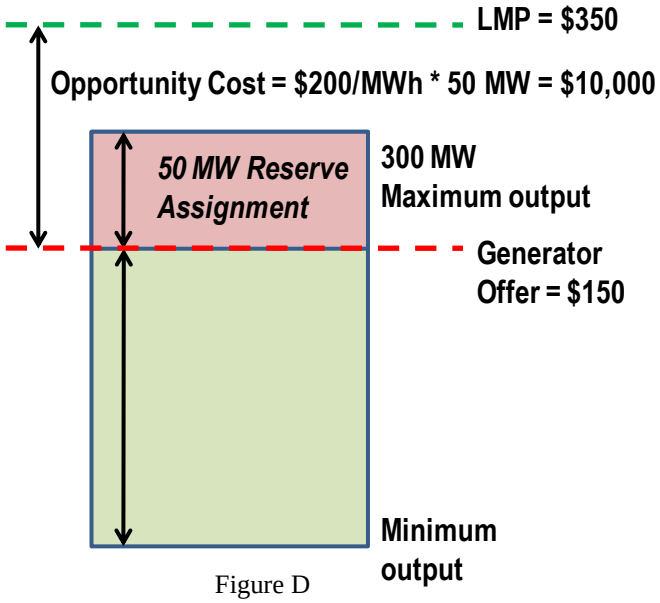

Figure D

Under this proposed option, if PJM were then to initiate scarcity conditions, the price of the reserve product this unit was assigned would be held constant at $200 per megawatt-hour. However, during the scarcity condition, the energy price would increase, likely up to the energy market offer cap of $1,000. Therefore, this unit's opportunity cost would increase to $8,500 per megawatt-hour ($1,000 per megawatt-hour minus $150 per megawatt-hour) times 50 megawatts, which equals $42,500. This condition is illustrated in Figure E below.

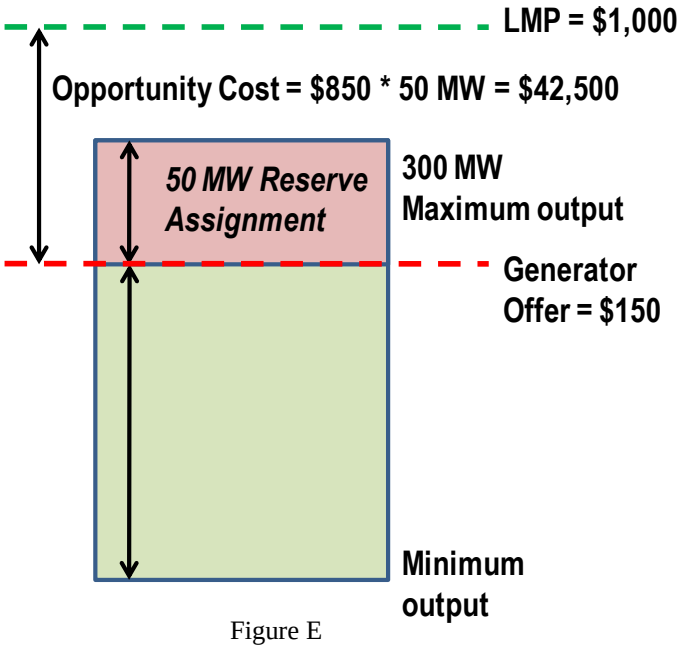

Figure E

However, since the price of the reserve product to which this unit was assigned would be held constant at $200 per megawatt-hour, all resources assigned to that product

would continue to be paid only that $200 per megawatt-hour clearing price. Therefore, to ensure that this unit does not lose money by following PJM's dispatch instructions to provide reserves, PJM must provide the unit with a Make-whole Payment of ($42,500 minus $10,000) or $32,500. Additionally, the Make-whole Payment would apply to any resource assigned this reserve product and for which its opportunity cost plus its offer price exceeded $10,000. Equally as important though, any resource that provides this reserve product but that does not experience an opportunity cost, such as storage resources, would not receive a Make-whole Payment and, therefore, would receive only the $200 per megawatt-hour clearing price.

This result during scarcity conditions would run contrary to the Commission's requirement that Make-whole Payments be eliminated. However, under the Administrative Cap Option, the Make-whole Payment would be necessary to ensure that resources followed PJM's dispatch instructions and provided reserve products instead of energy such that reliability can be maintained. Moreover, the ability for PJM dispatchers to count on resources' compliance with dispatch directives is most critical during scarcity conditions when the system is under the greatest stress. Unfortunately, these scarcity conditions are exactly the time when the real time, five-minute joint optimization would not result in the correct pricing result under this option because without the penalty factors proposed in PJM's compliance to Order No. 719, it would be impossible to accurately reflect all resources' opportunity costs in the reserve prices. As a result, the correct incentives could not be established through the prices resulting from the market's operation during these most critical times.

Consequently, while PJM will substantially reduce its Make-whole Payments under the Administrative Cap Option, it cannot eliminate Make-whole Payments completely. In fact the result of this option is that regulation prices will be lower than they should be when regulation is most needed on the grid. This result is counterproductive and could significantly reduce the effectiveness of FERC Order 755 in providing incentives for investment in alternative resources to provide grid services. Therefore, to properly compensate resources during synchronized shortages, PJM proposes to revise its market rules to provide a Make-whole Payment that ensures that resources are properly compensated with the actual lost opportunity costs of providing regulation. As described above, PJM proposes to modify its market rules to hold the price of regulation and reserves constant for the duration of the shortage event. However, the price of energy will continue to be market-based.[140] This may result in the price of energy for a particular settlement period during the shortage event being higher than the price of energy used to calculate the lost opportunity costs of regulation resources used in the regulation market-clearing price. In other words, the *actual* opportunity costs may be higher than the opportunity costs than those used to compensate resources. Therefore, under the Administrative Cap Option only, PJM proposes to add new section 3.2.2(i) to Schedule 1 of the Operating Agreement to provide resources with a Make-whole Payment when PJM is no longer able to meet its synchronized reserve requirement for a

[140] However, the overall energy price cap of $1,000 per megawatt-hour will continue to apply.

reserve region to ensure that regulation resources are properly compensated for all lost opportunity costs.

IV. PJM STAKEHOLDER REVIEW AND SUPPORT

PJM worked extensively with its stakeholders in an effort to revise and seek consensus on PJM's compensation methodology for regulation resources. Working primarily through the Regulation Performance Senior Task Force ("RPSTF") starting in April 2011, PJM and its stakeholders developed the proposed regulation compensation methodology described in this compliance filing, and the proposal was presented to, and discussed by, the PJM stakeholders at the (i) the Markets and Reliability Committee ("MRC") meetings on September 15, 2011, October 5, 2011, November 16, 2011, and December 21, 2011; and (ii) the Members Committee ("MC") meetings on November 11, 2011 and January 26, 2012.

Although PJM does not require stakeholder approval to submit the revisions proposed herein, PJM sought an indicative vote of the stakeholders nonetheless. The MRC endorsed and approved the Market-based Pricing Option revisions (excluding the revisions already pending in the Order No. 719 Compliance Filing) by acclamation of the members present at its meeting on December 21, 2011.[141] The MC endorsed and approved the same proposed revisions by acclamation of the members present at its meeting on January 26, 2012.[142] The RPSTF proposal consisted of the revisions proposed in section III above based on the assumption that that the joint optimization of energy, regulation, and reserves is fundamental to the proper pricing of each product and the joint optimization would be FERC prior to the implementation of the Order 755 compliance changes (i.e., revisions in section III). However, in the *Regulation Performance Senior Task Force Consensus Proposal Report*, PJM stated that it would request that the Commission include the joint optimization component of the Order No. 719 Compliance Filing in the Order 755 compliance filing if FERC had not approved the Order No. 719 Compliance Filing prior to PJM's Order No. 755 compliance.[143]

V. Effective Date

In order to satisfy the Commission's mandatory implementation date in Order No. 755, PJM requests that the Commission issue its order accepting the enclosed Operating Agreement and Tariff revisions for either the Market-based Pricing Option or Administrative Cap Option by no later than May 18, 2012 with an effective date of

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[141] The other revisions proposed herein are pending in the Order No. 719 Compliance Filing or necessary to effectuate the joint optimization of energy and ancillary services, as described in section III above. PJM did not present the Administrative Cap Option revisions to stakeholders for their approval. However, PJM did inform them that its Order No. 755 compliance filing would include this alternative option.

[142] Cite to the minutes of the MC here if they are posted on PJM's web site.

[143] *See* PJM, *Regulation Performance Senior Task Force Consensus Proposal Report*, http://www.pjm.com/~/media/committees-groups/committees/mrc/20111221/20111221-item-04-rpstf-report.ashx.

October 1, 2012[144] to afford PJM sufficient time to properly train PJM's operators, market participants, and implement the necessary software modifications. Additionally, because of the significant differences between the two proposed options, PJM is unable to completely develop the necessary software and therefore train operators and market participants on either option until the Commission issues its order accepting either the Market-based Pricing Option or Administrative Cap Option. Finally, should the Commission require substantive revisions to the Market-based Pricing Option or Administrative Cap Option, PJM may request a deferred effective date to accommodate any modifications to software modifications, operator training, or software to implement the Commission's directives.

VI. Documents Enclosed

PJM encloses with this transmittal letter, each of the following:

1) For the Market-based Pricing Option, PDF and electronic versions of the redline and clean versions of the Tariff and Operating Agreement sections with the revisions needed to comply with Order No 755, including pending Order No. 719 revisions, which are shown in italics;

2) Attachment A: Tariff and Operating Agreement revision chart with a side-by-side comparisons of the revisions for the Market-based Pricing Option and the Administrative Cap Option;

3) Attachment B: For the Administrative Cap Option, a redline and clean PDF version only of the Tariff and Operating Agreement sections with the revisions needed for Order No. 755 compliance[145]; and

4) Attachment C: *Affidavit of Adam J. Keech on Behalf of PJM Interconnection, L.L.C.*, PJM Director of Dispatch, System Operations.

VII. Correspondence and Communications

Correspondence and communications with respect to this filing should be sent to the following persons:

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[144] Although the Commission's deadline for implementation of Order No. 755 revisions is October 29, 2012, PJM must implement its proposed revisions on the first day of a month to properly align with PJM's billing cycle.

[145] Should the Commission choose to accept the Administrative Cap Option, PJM will submit redline and clean electronic versions of the Operating Agreement and Tariff for such option in a compliance filing.

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

James Burlew
Counsel
PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403
(610) 666-4345
burlej@pjm.com

VIII. Service

PJM has served a copy of this filing on all PJM Members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,[146] PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: http://www.pjm.com/documents/ferc-manuals/ferc-filings.aspx with a specific link to the newly-filed document, and will send an e-mail on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM Region[147] alerting them that this filing has been made by PJM and is available by following such link. If the document is not immediately available by using the referenced link, the document will be available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the 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,

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

James Burlew
Counsel
PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403
(610) 666-4345
burlej@pjm.com

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

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

Sections of the
PJM Open Access TransmissionTariff
and
PJM Operating Agreement

Marked/Redline Version

Additional coverpages separating Agreements

Sections of the
PJM Open Access TransmissionTariff

Marked/Redline Version

Definitions – R - S

1.36C Reasonable Efforts:

With respect to any action required to be made, attempted, or taken by an Interconnection Party or by a Construction Party under Part IV or Part VI of the Tariff, an Interconnection Service Agreement, or a Construction Service Agreement, such efforts as are timely and consistent with Good Utility Practice and with efforts that such party would undertake for the protection of its own interests.

1.37 Receiving Party:

The entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

1.37A Regional Transmission Expansion Plan:

The plan prepared by the Office of the Interconnection pursuant to Schedule 6 of the Operating Agreement for the enhancement and expansion of the Transmission System in order to meet the demands for firm transmission service in the PJM Region.

1.38 Regional Transmission Group (RTG):

A voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

1.38.01 Regulation Zone:

Any of those one or more geographic areas, each consisting of a combination of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, regulation service.

1.38.01A Relevant Electric Retail Regulatory Authority:

An entity that has jurisdiction over and establishes prices and policies for competition for providers of retail electric service to end-customers, such as the city council for a municipal utility, the governing board of a cooperative utility, the state public utility commission or any other such entity.

1.38A Reliability Assurance Agreement:

The Reliability Assurance Agreement Among Load Serving Entities in the PJM Region, Rate Schedule No. 44, dated as of May 28, 2009, and as amended from time to time thereafter.

1.38B [RESERVED]

1.38C Required Transmission Enhancements:

Enhancements and expansions of the Transmission System that (1) a Regional Transmission Expansion Plan developed pursuant to Schedule 6 of the Operating Agreement or (2) the Coordinated System Plan periodically developed pursuant to the Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. designates one or more of the Transmission Owner(s) or the transmission owners within the Midwest Independent System Operator to construct and own or finance.

1.38D Reserve Zone:

"Reserve Zone" shall mean any of those geographic areas consisting of a combination of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, reserve service.

1.39 Reserved Capacity:

The maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.39A Schedule of Work:

Shall mean that schedule attached to the Interconnection Construction Service Agreement setting forth the timing of work to be performed by the Constructing Entity pursuant to the Interconnection Construction Service Agreement, based upon the Facilities Study and subject to modification, as required, in accordance with Transmission Provider's scope change process for interconnection projects set forth in the PJM Manuals.

1.39B Scope of Work:

Shall mean that scope of the work attached as a schedule to the Interconnection Construction Service Agreement and to be performed by the Constructing Entity(ies) pursuant to the Interconnection Construction Service Agreement, provided that such Scope of Work may be modified, as required, in accordance with Transmission Provider's scope change process for interconnection projects set forth in the PJM Manuals.

1.39C Secondary Systems:

Control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers.

1.39D Security:

The security provided by the New Service Customer pursuant to Section 212.4 or Section 213.4 of the Tariff to secure the New Service Customer's responsibility for Costs under the Interconnection Service Agreement or Upgrade Construction Service Agreement and Section 217 of the Tariff.

1.40 Service Agreement:

The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

1.41 Service Commencement Date:

The date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Section 15.3 or Section 29.1 under the Tariff.

1.42 Short-Term Firm Point-To-Point Transmission Service:

Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of less than one year.

1.42a Site:

All of the real property, including but not limited to any leased real property and easements, on which the Customer Facility is situated and/or on which the Customer Interconnection Facilities are to be located.

1.42.01 Small Inverter Facility:

An Energy Resource that is a certified small inverter-based facility no larger than 10 kW.

1.42.02 Small Inverter ISA:

An agreement among Transmission Provider, Interconnection Customer, and Interconnected Transmission Owner regarding interconnection of a Small Inverter Facility under section 112B of Part IV of the Tariff.

1.42A [RESERVED]

1.42B [RESERVED]

1.42C [RESERVED]

1.42D State:

The term "state" shall mean a state of the United States or the District of Columbia.

1.42D.01 Switching and Tagging Rules:

The switching and tagging procedures of Interconnected Transmission Owners and Interconnection Customer as they may be amended from time to time.

1.42E ~~*Synchronized Reserve Zone:*~~

~~*Any of those geographic areas consisting of a combination of one or more of the Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, Synchronized Reserve service.*~~[RESERVED]

1.42F System Condition:

A specified condition on the Transmission Provider's system or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm Point-to-Point Transmission Service using the curtailment priority pursuant to Section 13.6. Such conditions must be identified in the Transmission Customer's Service Agreement.

1.43 System Impact Study:

An assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a Completed Application, an Interconnection Request or an Upgrade Request, (ii) whether any additional costs may be incurred in order to provide such transmission service or to accommodate an Interconnection Request, and (iii) with respect to an Interconnection Request, an estimated date that an Interconnection Customer's Customer Facility can be interconnected with the Transmission System and an estimate of the Interconnection Customer's cost responsibility for the interconnection; and (iv) with respect to an Upgrade Request, the estimated cost of the requested system upgrades or expansion, or of the cost of the system upgrades or expansion, necessary to provide the requested incremental rights.

1.43.01 System Protection Facilities:

The equipment required to protect (i) the Transmission System, other delivery systems and/or other generating systems connected to the Transmission System from faults or other electrical disturbance occurring at or on the Customer Facility, and (ii) the Customer Facility from faults or other electrical system disturbance occurring on the Transmission System or on other delivery systems and/or other generating systems to which the Transmission System is directly or indirectly connected. System Protection Facilities shall include such protective and regulating devices as are identified in the Applicable Technical Requirements and Standards or that are required by Applicable Laws and Regulations or other Applicable Standards, or as are otherwise necessary to protect personnel and equipment and to minimize deleterious effects to the Transmission System arising from the Customer Facility.

SCHEDULE 3
Regulation and Frequency Response Service

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

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

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

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

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

d. A resource capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced from the Regulation range by at least twice the amount of the Regulation provided~~.~~ with consideration of ~~The~~ the ~~amount of~~ Regulation limits of the ~~provided by a~~ resource, as specified in the PJM Manuals ~~shall serve to redefine the normal minimum generation and normal maximum generation energy limits of that unit, in that the~~

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

e. Qualified Regulation must satisfy the measurement and verification tests described in the ~~procedures of the Office of the Interconnection~~PJM Manuals.

f. A Transmission Owner, Network Customer or other Transmission Customer may satisfy its Regulation obligation from its own resources capable of performing Regulation service, by contractual arrangements with others able to provide Regulation service on a comparable basis, or by purchases from the PJM Regulation market.

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

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

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

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

1.3 Definitions.

1.3.1 Acceleration Request.

"Acceleration Request" shall mean a request pursuant to section 1.9.4A of this Schedule to accelerate or reschedule a transmission outage scheduled pursuant to sections 1.9.2 or 1.9.4.

1.3.1A Auction Revenue Rights.

"Auction Revenue Rights" or "ARRs" shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Section 7.4 of this Schedule.

1.3.1B Auction Revenue Rights Credits.

"Auction Revenue Rights Credits" shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Section 7.4.3 of this Schedule.

1.3.1B.01 Batch Load Demand Resource.

"Batch Load Demand Resource" shall mean a Demand Resource that has a cyclical production process such that at most times during the process it is consuming energy, but at consistent regular intervals, ordinarily for periods of less than ten minutes, it reduces its consumption of energy for its production processes to minimal or zero megawatts.

1.3.1B.02 Congestion Price.

"Congestion Price" shall mean the congestion component of the Locational Marginal Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.1B.03 Curtailment Service Provider.

"Curtailment Service Provider" or "CSP" shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market by causing a reduction in demand.

1.3.1B.04 Day-ahead Congestion Price.

"Day-ahead Congestion Price" shall mean the Congestion Price resulting from the Day-ahead Energy Market.

1.3.1C Day-ahead Energy Market.

"Day-ahead Energy Market" shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Section 1.10 of this Schedule.

1.3.1C.01 Day-ahead Loss Price.

"Day-ahead Loss Price" shall mean the Loss Price resulting from the Day-ahead Energy Market.

1.3.1D Day-ahead Prices.

"Day-ahead Prices" shall mean the Locational Marginal Prices resulting from the Day-ahead Energy Market.

1.3.1D.01 Day-ahead Scheduling Reserves.

"Day-ahead Scheduling Reserves" shall mean thirty-minute reserves as defined by the Reliability First Corporation and SERC.

1.3.1D.02 Day-ahead Scheduling Reserves Requirement.

"Day-ahead Scheduling Reserves Requirement" shall mean the thirty-minute reserve requirement for the PJM Region established consistent with Reliability First Corporation and SERC reliability standards, or those of any additional and/or successor regional reliability organization(s) that are responsible for establishing reliability requirements for the PJM Region, plus any additional thirty-minute reserves scheduled in response to an RTO-wide Hot or Cold Weather Alert or other reasons for conservative operations.

1.3.1D.03 Day-ahead Scheduling Reserves Resources.

"Day-ahead Scheduling Reserves Resources" shall mean synchronized and non-synchronized generation resources and Demand Resources electrically located within the PJM Region that are capable of providing Day-ahead Scheduling Reserves.

1.3.1D.04 Day-ahead Scheduling Reserves Market.

"Day-ahead Scheduling Reserves Market" shall mean the schedule of commitments for the purchase or sale of Day-ahead Scheduling Reserves developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Section 1.10 of this Schedule.

1.3.1D.05 Day-ahead System Energy Price.

"Day-ahead System Energy Price" shall mean the System Energy Price resulting from the Day-ahead Energy Market.

1.3.1E Decrement Bid.

"Decrement Bid" shall mean a bid to purchase energy at a specified location in the Day-ahead Energy Market. An accepted Decrement Bid results in scheduled load at the specified location in the Day-ahead Energy Market.

1.3.1E.01 Demand Resource.

"Demand Resource" shall mean a resource with the capability to provide a reduction in demand.

1.3.1F Dispatch Rate.

"Dispatch Rate" shall mean the control signal, expressed in dollars per megawatt-hour, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by the Office of the Interconnection in accordance with the Offer Data.

1.3.1G Energy Storage Resource.

"Energy Storage Resource" shall mean flywheel or battery storage facility solely used for short term storage and injection of energy at a later time to participate in the PJM energy and/or Ancilliary Services markets as a Market Seller.

1.3.2 Equivalent Load.

"Equivalent Load" shall mean the sum of a Market Participant's net system requirements to serve its customer load in the PJM Region, if any, plus its net bilateral transactions.

1.3.2A Economic Load Response Participant.

"Economic Load Response Participant" shall mean a Member or Special Member that qualifies under Section 1.5A of this Schedule to participate in the PJM Interchange Energy Market through reductions in demand.

1.3.2A.01 Economic Minimum.

"Economic Minimum" shall mean the lowest incremental MW output level a unit can achieve while following economic dispatch.

1.3.2B Energy Market Opportunity Cost.

"Energy Market Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of available run hours due to limitations imposed on the unit by Applicable Laws and Regulations (as defined in PJM Tariff), and (b) the forecasted future hourly Locational Marginal Price at which the generating

unit could run while not violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Schedule 2 of the Operating Agreement.

1.3.3 External Market Buyer.

"External Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for consumption by end-users outside the PJM Region, or for load in the PJM Region that is not served by Network Transmission Service.

1.3.4 External Resource.

"External Resource" shall mean a generation resource located outside the metered boundaries of the PJM Region.

1.3.5 Financial Transmission Right.

"Financial Transmission Right" or "FTR" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2 of this Schedule.

1.3.5A Financial Transmission Right Obligation.

"Financial Transmission Right Obligation" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2(b) of this Schedule.

1.3.5B Financial Transmission Right Option.

"Financial Transmission Right Option" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2(c) of this Schedule.

1.3.6 Generating Market Buyer.

"Generating Market Buyer" shall mean an Internal Market Buyer that is a Load Serving Entity that owns or has contractual rights to the output of generation resources capable of serving the Market Buyer's load in the PJM Region, or of selling energy or related services in the PJM Interchange Energy Market or elsewhere.

1.3.7 Generator Forced Outage.

"Generator Forced Outage" shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the PJM Manuals. A reduction in output or

removal from service of a generating unit in response to changes in market conditions shall not constitute a Generator Forced Outage.

1.3.8 Generator Maintenance Outage.

"Generator Maintenance Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform necessary repairs on specific components of the facility, if removal of the facility meets the guidelines specified in the PJM Manuals.

1.3.9 Generator Planned Outage.

"Generator Planned Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the Office of the Interconnection in accordance with the PJM Manuals.

1.3.9A Increment Bid.

"Increment Bid" shall mean an offer to sell energy at a specified location in the Day-ahead Energy Market. An accepted Increment Bid results in scheduled generation at the specified location in the Day-ahead Energy Market.

1.3.9B Interface Pricing Point.

"Interface Pricing Point" shall have the meaning specified in section 2.6A.

1.3.10 Internal Market Buyer.

"Internal Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for ultimate consumption by end-users inside the PJM Region that are served by Network Transmission Service.

1.3.11 Inadvertent Interchange.

"Inadvertent Interchange" shall mean the difference between net actual energy flow and net scheduled energy flow into or out of the individual Control Areas operated by PJM.

1.3.11.01 Load Management.

"Load Management" shall mean either a Demand Resource ("DR") or an Interruptible Load for Reliability ("ILR") resource, both as defined in the Reliability Assurance Agreement.

1.3.11A Load Reduction Event.

"Load Reduction Event" shall mean a reduction in demand by a Member or Special Member for the purpose of participating in the PJM Interchange Energy Market.

1.3.11B Loss Price.

"Loss Price" shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.12 Market Operations Center.

"Market Operations Center" shall mean the equipment, facilities and personnel used by or on behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

1.3.12A Maximum Emergency.

"Maximum Emergency" shall mean the designation of all or part of the output of a generating unit for which the designated output levels may require extraordinary procedures and therefore are available to the Office of the Interconnection only when the Office of the Interconnection declares a Maximum Generation Emergency and requests generation designated as Maximum Emergency to run. The Office of the Interconnection shall post on the PJM website the aggregate amount of megawatts that are classified as Maximum Emergency.

1.3.13 Maximum Generation Emergency.

"Maximum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection to address either a generation or transmission emergency in which the Office of the Interconnection anticipates requesting one or more Generation Capacity Resources, or Non-Retail Behind The Meter Generation resources to operate at its maximum net or gross electrical power output, subject to the equipment stress limits for such Generation Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

1.3.14 Minimum Generation Emergency.

"Minimum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

1.3.14A NERC Interchange Distribution Calculator.

"NERC Interchange Distribution Calculator" shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

1.3.14B Net Benefits Test.

"Net Benefits Test" shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Section 3.3A.4 of this Schedule.

1.3.15 Network Resource.

"Network Resource" shall have the meaning specified in the PJM Tariff.

1.3.16 Network Service User.

"Network Service User" shall mean an entity using Network Transmission Service.

1.3.17 Network Transmission Service.

"Network Transmission Service" shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part III of the PJM Tariff, or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

1.3.17A Non-Regulatory Opportunity Cost.

"Non-Regulatory Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, (ii) a fuel supply limitation, for up to one year, resulting from an event of force majeure; and, (b) the forecasted future hourly Locational Marginal Price at which the generating unit could run while not violating such limitations. Non-Regulatory Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same period of time in which the unit is bound by the referenced restrictions, and is reflected in the rules set forth in PJM Manual 15. Non-Regulatory Opportunity Costs shall be limited to those resources which are specifically delineated in Schedule 2 of the Operating Agreement.

1.3.17B Non-Synchronized Reserve.

"Non-Synchronized Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

1.3.17C Non-Synchronized Reserve Event.

"Non-Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources and/or Demand Resources able, assigned or self-scheduled, to provide

Non-Synchronized Reserve within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-schedule Non-Synchronized Reserve capability.

1.3.17DB Non-Variable Loads.

"Non-Variable Loads" shall have the meaning specified in section 1.5A.6 of this Schedule.

1.3.18 Normal Maximum Generation.

"Normal Maximum Generation" shall mean the highest output level of a generating resource under normal operating conditions.

1.3.19 Normal Minimum Generation.

"Normal Minimum Generation" shall mean the lowest output level of a generating resource under normal operating conditions.

1.3.20 Offer Data.

"Offer Data" shall mean the scheduling, operations planning, dispatch, new resource, and other data and information necessary to schedule and dispatch generation resources and Demand Resource(s) for the provision of energy and other services and the maintenance of the reliability and security of the transmission system in the PJM Region, and specified for submission to the PJM Interchange Energy Market for such purposes by the Office of the Interconnection.

1.3.21 Office of the Interconnection Control Center.

"Office of the Interconnection Control Center" shall mean the equipment, facilities and personnel used by the Office of the Interconnection to coordinate and direct the operation of the PJM Region and to administer the PJM Interchange Energy Market, including facilities and equipment used to communicate and coordinate with the Market Participants in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

1.3.21A On-Site Generators.

"On-Site Generators" shall mean generation facilities (including Behind The Meter Generation) that (i) are not Capacity Resources, (ii) are not injecting into the grid, (iii) are either synchronized or non-synchronized to the Transmission System, and (iv) can be used to reduce demand for the purpose of participating in the PJM Interchange Energy Market.

1.3.22 Operating Day.

"Operating Day" shall mean the daily 24 hour period beginning at midnight for which transactions on the PJM Interchange Energy Market are scheduled.

1.3.23 Operating Margin.

"Operating Margin" shall mean the incremental adjustments, measured in megawatts, required in PJM Region operations in order to accommodate, on a first contingency basis, an operating contingency in the PJM Region resulting from operations in an interconnected Control Area. Such adjustments may result in constraints causing Transmission Congestion Charges, or may result in Ancillary Services charges pursuant to the PJM Tariff.

1.3.24 Operating Margin Customer.

"Operating Margin Customer" shall mean a Control Area purchasing Operating Margin pursuant to an agreement between such other Control Area and the LLC.

1.3.25 PJM Interchange.

"PJM Interchange" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load exceeds, or is exceeded by, the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup; or (c) the hourly scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the hourly net metered output of any other Market Seller; or (e) the hourly scheduled deliveries of Spot Market Energy to an External Market Buyer; or (f) the hourly scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

1.3.26 PJM Interchange Export.

"PJM Interchange Export" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load is exceeded by the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup sales; or (c) the hourly scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the hourly net metered output of any other Market Seller.

1.3.27 PJM Interchange Import.

"PJM Interchange Import" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load exceeds the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup purchases; or (c) the hourly scheduled deliveries of Spot Market Energy to an External Market Buyer; or (d) the hourly scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

1.3.28 PJM Open Access Same-time Information System.

"PJM Open Access Same-time Information System" shall mean the electronic communication system for the collection and dissemination of information about transmission services in the PJM Region, established and operated by the Office of the Interconnection in accordance with FERC standards and requirements.

1.3.28A Planning Period Quarter.

"Planning Period Quarter" shall mean any of the following three month periods in the Planning Period: June, July and August; September, October and November; December, January and February; or, March, April and May.

1.3.28B Planning Period Balance.

"Planning Period Balance" shall mean the entire period of time remaining in the Planning Period following the month that a monthly auction is conducted.

1.3.29 Point-to-Point Transmission Service.

"Point-to-Point Transmission Service" shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part II of the PJM Tariff.

1.3.29A PRD Curve

PRD Curve shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29B PRD Provider

PRD Provider shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29C PRD Reservation Price

PRD Reservation Price shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29D PRD Substation

PRD Substation shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29E Price Responsive Demand

Price Responsive Demand shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29F Primary Reserve

"Primary Reserve" shall mean the total reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes of a request from the Office of the Interconnection dispatcher, and is comprised of both Synchronized Reserve and Non-Synchronized Reserve.

1.3.30 Ramping Capability.

"Ramping Capability" shall mean the sustained rate of change of generator output, in megawatts per minute.

1.3.30.01 Real-time Congestion Price.

"Real-time Congestion Price" shall mean the Congestion Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30.02 Real-time Loss Price.

"Real-time Loss Price" shall mean the Loss Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30A Real-time Prices.

"Real-time Prices" shall mean the Locational Marginal Prices resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30B Real-time Energy Market.

"Real-time Energy Market" shall mean the purchase or sale of energy and payment of Transmission Congestion Charges for quantity deviations from the Day-ahead Energy Market in the Operating Day.

1.3.30B.01 Real-time System Energy Price.

"Real-time System Energy Price" shall mean the System Energy Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.31 Regulation.

"Regulation" shall mean the capability of a specific generation resource or Demand Resource with appropriate telecommunications, control and response capability to increase or decrease its output or adjust load in response to a regulating control signal, in accordance with the specifications in the PJM Manuals.

1.3.31.001 Reserve Penalty Factor.

"Reserve Penalty Factor" shall mean the cost, in $/MWh, associated with being unable to meet a specific reserve requirement in a Reserve Zone. A Reserve Penalty Factor will be defined for each reserve requirement in a Reserve Zone.

1.3.31.01 Residual Auction Revenue Rights.

"Residual Auction Revenue Rights" shall mean incremental stage 1 Auction Revenue Rights created within a Planning Period by an increase in transmission system capability or a change in any other relevant factor that was not modeled pursuant to section 7.5 of Schedule 1 of this Agreement in compliance with section 7.4.2 (h) of Schedule 1 of this Agreement, and, if modeled, would have increased the amount of stage 1 Auction Revenue Rights allocated pursuant to section 7.4.2 of Schedule 1 of this Agreement; provided that, the foregoing notwithstanding, Residual Auction Revenue Rights shall exclude: 1) Incremental Auction Revenue Rights allocated pursuant to Part VI of the Tariff; and 2) Auction Revenue Rights allocated to entities that are assigned cost responsibility pursuant to Schedule 6 of this Agreement for transmission upgrades that create such rights.

1.3.31.02 Special Member.

"Special Member" shall mean an entity that satisfies the requirements of Section 1.5A.02 of this Schedule or the special membership provisions established under the Emergency Load Response Program.

1.3.31A [Reserved.]

1.3.31B [Reserved.]

1.3.32 Spot Market Backup.

"Spot Market Backup" shall mean the purchase of energy from, or the delivery of energy to, the PJM Interchange Energy Market in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason.

1.3.33 Spot Market Energy.

"Spot Market Energy" shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at System Energy Prices determined as specified in Section 2 of this Schedule.

1.3.33A State Estimator.

"State Estimator" shall mean the computer model of power flows specified in Section 2.3 of this Schedule.

1.3.33B Station Power.

"Station Power" shall mean energy used for operating the electric equipment on the site of a generation facility located in the PJM Region or for the heating, lighting, air-conditioning and office equipment needs of buildings on the site of such a generation facility that are used in the operation, maintenance, or repair of the facility. Station Power does not include any energy (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility; (iii) used for compressors at a compressed air energy storage facility; (iv) used for charging an Energy Storage Resource; or (v) used in association with restoration or black start service.

1.3.33B.01 Synchronized Reserve.

"Synchronized Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes from the request of the Office of the Interconnection dispatcher, and is provided by equipment that is electrically synchronized to the Transmission System.

1.3.33B.02 Synchronized Reserve Event.

"Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources and/or Demand Resources able, assigned or self-scheduled, to provide Synchronized Reserve within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-scheduled Synchronized Reserve capability.

1.3.33B.03 System Energy Price.

"System Energy Price" shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.33C Target Allocation.

"Target Allocation" shall mean the allocation of Transmission Congestion Credits as set forth in Section 5.2.3 of this Schedule or the allocation of Auction Revenue Rights Credits as set forth in Section 7.4.3 of this Schedule.

1.3.34 Transmission Congestion Charge.

"Transmission Congestion Charge" shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses in accordance with Section 9.3, which shall be calculated and allocated as specified in Section 5.1 of this Schedule.

1.3.35 Transmission Congestion Credit.

"Transmission Congestion Credit" shall mean the allocated share of total Transmission Congestion Charges credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section 5.2 of this Schedule.

1.3.36 Transmission Customer.

"Transmission Customer" shall mean an entity using Point-to-Point Transmission Service.

1.3.37 Transmission Forced Outage.

"Transmission Forced Outage" shall mean an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the PJM Manuals. A removal from service of a transmission facility at the request of the Office of the Interconnection to improve transmission capability shall not constitute a Forced Transmission Outage.

1.3.37A Transmission Loading Relief.

"Transmission Loading Relief" shall mean NERC's procedures for preventing operating security limit violations, as implemented by PJM as the security coordinator responsible for maintaining transmission security for the PJM Region.

1.3.37B Transmission Loading Relief Customer.

"Transmission Loading Relief Customer" shall mean an entity that, in accordance with Section 1.10.6A, has elected to pay Transmission Congestion Charges during Transmission Loading Relief in order to continue energy schedules over contract paths outside the PJM Region that are increasing the cost of energy in the PJM Region.

1.3.37C Transmission Loss Charge.

"Transmission Loss Charge" shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Section 5 of this Schedule.

1.3.38 Transmission Planned Outage.

"Transmission Planned Outage" shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in this Agreement or the PJM Manuals.

1.3.38A Variable Loads.

"Variable Loads" shall have the meaning specified in section 1.5A.6 of this Schedule.

1.3.39 Zonal Base Load.

"Zonal Base Load" shall mean the lowest daily zonal peak load from the twelve month period ending October 21 of the calendar year immediately preceding the calendar year in which an annual Auction Revenue Right allocation is conducted, increased by the projected load growth rate for the relevant Zone.

1.7 General.

1.7.1 Market Sellers.

Only Market Sellers shall be eligible to submit offers to the Office of the Interconnection for the sale of electric energy or related services in the PJM Interchange Energy Market. Market Sellers shall comply with the prices, terms, and operating characteristics of all Offer Data submitted to and accepted by the PJM Interchange Energy Market.

1.7.2 Market Buyers.

Only Market Buyers shall be eligible to purchase energy or related services in the PJM Interchange Energy Market. Market Buyers shall comply with all requirements for making purchases from the PJM Interchange Energy Market.

1.7.2A Economic Load Response Participants.

Only Economic Load Response Participants shall be eligible to participate in the Real-time Energy Market and the Day-ahead Energy Market by submitting offers to the Office of the Interconnection to reduce demand.

1.7.3 Agents.

A Market Participant may participate in the PJM Interchange Energy Market through an agent, provided that the Market Participant informs the Office of the Interconnection in advance in writing of the appointment of such agent. A Market Participant participating in the PJM Interchange Energy Market through an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the PJM Interchange Energy Market, and shall ensure that any such agent complies with the requirements of this Agreement.

1.7.4 General Obligations of the Market Participants.

(a) In performing its obligations to the Office of the Interconnection hereunder, each Market Participant shall at all times (i) follow Good Utility Practice, (ii) comply with all applicable laws and regulations, (iii) comply with the applicable principles, guidelines, standards and requirements of FERC, NERC and Applicable Regional Reliability Councils, (iv) comply with the procedures established for operation of the PJM Interchange Energy Market and PJM Region and (v) cooperate with the Office of the Interconnection as necessary for the operation of the PJM Region in a safe, reliable manner consistent with Good Utility Practice.

(b) Market Participants shall undertake all operations in or affecting the PJM Interchange Energy Market and the PJM Region including but not limited to compliance with all Emergency procedures, in accordance with the power and authority of the Office of the Interconnection with respect to the operation of the PJM Interchange Energy Market and the PJM Region as established in this Agreement, and as specified in the Schedules to this Agreement and the PJM Manuals. Failure to comply with the foregoing operational

requirements shall subject a Market Participant to such reasonable charges or other remedies or sanctions for non-compliance as may be established by the PJM Board, including legal or regulatory proceedings as authorized by the PJM Board to enforce the obligations of this Agreement.

(c) The Office of the Interconnection may establish such committees with a representative of each Market Participant, and the Market Participants agree to provide appropriately qualified personnel for such committees, as may be necessary for the Office of the Interconnection and PJMSettlement to perform its obligations hereunder.

(d) All Market Participants shall provide to the Office of the Interconnection the scheduling and other information specified in the Schedules to this Agreement, and such other information as the Office of the Interconnection may reasonably require for the reliable and efficient operation of the PJM Region and PJM Interchange Energy Market, and for compliance with applicable regulatory requirements for posting market and related information. Such information shall be provided as much in advance as possible, but in no event later than the deadlines established by the Schedules to this Agreement, or by the Office of the Interconnection in conformance with such Schedules. Such information shall include, but not be limited to, maintenance and other anticipated outages of generation or transmission facilities, scheduling and related information on bilateral transactions and self-scheduled resources, and implementation of active load management, interruption of load, Price Responsive Demand, and other load reduction measures. The Office of the Interconnection shall abide by appropriate requirements for the non-disclosure and protection of any confidential or proprietary information given to the Office of the Interconnection by a Market Participant. Each Market Participant shall maintain or cause to be maintained compatible information and communications systems, as specified by the Office of the Interconnection, required to transmit scheduling, dispatch, or other time-sensitive information to the Office of the Interconnection in a timely manner.

(e) Subject to the requirements for Economic Load Response Participants in section 1.5A above, each Market Participant shall install and operate, or shall otherwise arrange for, metering and related equipment capable of recording and transmitting all voice and data communications reasonably necessary for the Office of the Interconnection and PJMSettlement to perform the services specified in this Agreement. A Market Participant that elects to be separately billed for its PJM Interchange shall, to the extent necessary, be individually metered in accordance with Section 14 of this Agreement, or shall agree upon an allocation of PJM Interchange between it and the Market Participant through whose meters the unmetered Market Participant's PJM Interchange is delivered. The Office of the Interconnection shall be notified of the allocation by the foregoing Market Participants.

(f) Each Market Participant shall operate, or shall cause to be operated, any generating resources owned or controlled by such Market Participant that are within the PJM Region or otherwise supplying energy to or through the PJM Region in a manner that is consistent with the standards, requirements or directions of the Office of the Interconnection and that will permit the Office of the Interconnection to perform its obligations under this Agreement; provided, however, no Market Participant shall be required to take any action that is inconsistent with Good Utility Practice or applicable law.

(g) Each Market Participant shall follow the directions of the Office of the Interconnection to take actions to prevent, manage, alleviate or end an Emergency in a manner consistent with this Agreement and the procedures of the PJM Region as specified in the PJM Manuals.

(h) Each Market Participant shall obtain and maintain all permits, licenses or approvals required for the Market Participant to participate in the PJM Interchange Energy Market in the manner contemplated by this Agreement.

(i) Consistent with Section 36.1.1 of the PJM Tariff, to the extent its generating facility is dispatchable, a Market Participant shall submit an Economic Minimum in the Real-time Energy Market that is no greater than the higher of its physical operating minimum or its Capacity Interconnection Rights, as that term is defined in the PJM Tariff, associated with such generating facility under its Interconnection Service Agreement under Attachment O of the PJM Tariff or a wholesale market participation agreement.

1.7.5 Market Operations Center.

Each Market Participant shall maintain a Market Operations Center, or shall make appropriate arrangements for the performance of such services on its behalf. A Market Operations Center shall meet the performance, equipment, communications, staffing and training standards and requirements specified in this Agreement for the scheduling and completion of transactions in the PJM Interchange Energy Market and the maintenance of the reliable operation of the PJM Region, and shall be sufficient to enable (i) a Market Seller or an Economic Load Response Participant to perform all terms and conditions of its offers to the PJM Interchange Energy Market, and (ii) a Market Buyer or an Economic Load Response Participant to conform to the requirements for purchasing from the PJM Interchange Energy Market.

1.7.6 Scheduling and Dispatching.

(a) The Office of the Interconnection shall schedule and dispatch in real-time generation resources and/or Demand Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Sellers, continuing until sufficient generation resources and/or Demand Resources are dispatched to serve the PJM Interchange Energy Market energy purchase requirements under normal system conditions of the Market Buyers (taking into account any reductions to such requirements in accordance with PRD Curves properly submitted by PRD Providers), as well as the requirements of the PJM Region for ancillary services provided by generation resources and/or Demand Resources, in accordance with this Agreement. Such scheduling and dispatch shall recognize transmission constraints on coordinated flowgates external to the Transmission System in accordance with Appendix A to the Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38) and on other such flowgates that are coordinated in accordance with

agreements between the LLC and other entities. Scheduling and dispatch shall be conducted in accordance with this Agreement.

(b) The Office of the Interconnection shall undertake to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the PJM Interchange Energy Market, and any relevant procedures of another Control Area, or any tariff (including the PJM Tariff). Upon determining that any such conflict or incompatibility exists, the Office of the Interconnection shall propose tariff or procedural changes, and undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

(c) To protect its generation or distribution facilities, or local Transmission Facilities not under the monitoring responsibility and dispatch control of the Office of the Interconnection, an entity may request that the Office of the Interconnection schedule and dispatch generation or reductions in demand to meet a limit on Transmission Facilities different from that which the Office of the Interconnection has determined to be required for reliable operation of the Transmission System. To the extent consistent with its other obligations under this Agreement, the Office of the Interconnection shall schedule and dispatch generation and reductions in demand in accordance with such request. An entity that makes a request pursuant to this section 1.7.6(c) shall be responsible for all generation and other costs resulting from its request that would not have been incurred by operating the Transmission System and scheduling and dispatching generation in the manner that the Office of the Interconnection otherwise has determined to be required for reliable operation of the Transmission System.

1.7.7 Pricing.

The price paid for energy bought and sold in the PJM Interchange Energy Market and for demand reductions will reflect the hourly Locational Marginal Price at each load and generation bus, determined by the Office of the Interconnection in accordance with this Agreement. Transmission Congestion Charges and Transmission Loss Charges, which shall be determined by differences in Congestion Prices and Loss Prices in an hour, shall be calculated by the Office of the Interconnection, and collected by PJMSettlement, and the revenues therefrom shall be disbursed by PJMSettlement in accordance with this Schedule.

1.7.8 Generating Market Buyer Resources.

A Generating Market Buyer may elect to self-schedule its generation resources up to that Generating Market Buyer's Equivalent Load, in accordance with and subject to the procedures specified in this Schedule, and the accounting and billing requirements specified in Section 3 to this Schedule. PJMSettlement shall not be a contracting party with respect to such self-scheduled or self-supplied transactions.

1.7.9 Delivery to an External Market Buyer.

A purchase of Spot Market Energy by an External Market Buyer shall be delivered to a bus or busses at the electrical boundaries of the PJM Region specified by the Office of the Interconnection, or to load in such area that is not served by Network Transmission Service,

using Point-to-Point Transmission Service paid for by the External Market Buyer. Further delivery of such energy shall be the responsibility of the External Market Buyer.

1.7.10 Other Transactions.

(a) Bilateral Transactions.

(i) In addition to transactions in the PJM Interchange Energy Market, Market Participants may enter into bilateral contracts for the purchase or sale of electric energy to or from each other or any other entity, subject to the obligations of Market Participants to make Generation Capacity Resources available for dispatch by the Office of the Interconnection. Such bilateral contracts shall be for the physical transfer of energy to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its eSchedules and Enhanced Energy Scheduler tools.

(ii) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of energy to a Market Participant inside the PJM Region, title to the energy that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and the further transmission of the energy or further sale of the energy into the PJM Interchange Energy Market shall be transacted by the buyer under the bilateral contract. With respect to all bilateral contracts for the physical transfer of energy to an entity outside the PJM Region, title to the energy shall pass to the buyer at the border of the PJM Region and shall be delivered to the border using transmission service. In no event shall the purchase and sale of energy between Market Participants under a bilateral contract constitute a transaction in the PJM Interchange Energy Market or be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

(iii) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of energy reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the megawatt hours of such reported transactions to amounts reflecting the expected load and other physical delivery obligations of the buyer under the bilateral contract.

(iv) All payments and related charges for the energy associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. 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 a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

(v) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any Spot Market Backup used to meet the bilateral contract seller's obligation to deliver energy under the bilateral contract and

for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new eSchedules or Enhanced Energy Scheduler reporting by the Market Participant and (ii) terminate all of the Market Participant's eSchedules and Enhanced Energy Schedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the eSchedules and Enhanced Energy Schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection. PJMSettlement shall assign its claims against a seller with respect to a seller's nonpayment for Spot Market Backup to a buyer to the extent that the buyer has made an indemnification payment to PJMSettlement with respect to the seller's nonpayment.

(vi) Bilateral contracts that do not contemplate the physical transfer of energy to or from a Market Participant are not subject to this Schedule, shall not be reported to and coordinated with the Office of the Interconnection, and shall not in any way constitute a transaction in the PJM Interchange Energy Market.

(b) Market Participants shall have Spot Market Backup with respect to all bilateral transactions that contemplate the physical transfer of energy to or from a Market Participant, that are not dynamically scheduled pursuant to Section 1.12 and that are curtailed or interrupted for any reason (except for curtailments or interruptions through active load management for load located within the PJM Region).

(c) To the extent the Office of the Interconnection dispatches a Generating Market Buyer's generation resources, such Generating Market Buyer may elect to net the output of such resources against its hourly Equivalent Load. Such a Generating Market Buyer shall be deemed a buyer from the PJM Interchange Energy Market to the extent of its PJM Interchange Imports, and shall be deemed a seller to the PJM Interchange Energy Market to the extent of its PJM Interchange Exports.

(d) A Market Seller may self-supply Station Power for its generation facility in accordance with the following provisions:

(i) A Market Seller may self-supply Station Power for its generation facility during any month (1) when the net output of such facility is positive, or (2) when the net output of such facility is negative and the Market Seller during the same month has available at other of its generation facilities positive net output in an amount at least sufficient to offset fully such negative net output. For purposes of this subsection (d), "net output" of a generation facility during any month means the facility's gross energy output, less the Station Power requirements of such facility, during that month. The determination of a generation facility's or a Market Seller's monthly net output under this subsection (d) will apply only to determine whether the Market Seller self-supplied

Station Power during the month and will not affect the price of energy sold or consumed by the Market Seller at any bus during any hour during the month. For each hour when a Market Seller has positive net output and delivers energy into the Transmission System, it will be paid the LMP at its bus for that hour for all of the energy delivered. Conversely, for each hour when a Market Seller has negative net output and has received Station Power from the Transmission System, it will pay the LMP at its bus for that hour for all of the energy consumed.

(ii) Transmission Provider will determine the extent to which each affected Market Seller during the month self-supplied its Station Power requirements or obtained Station Power from third-party providers (including affiliates) and will incorporate that determination in its accounting and billing for the month. In the event that a Market Seller self-supplies Station Power during any month in the manner described in subsection (1) of subsection (d)(i) above, Market Seller will not use, and will not incur any charges for, transmission service. In the event, and to the extent, that a Market Seller self-supplies Station Power during any month in the manner described in subsection (2) of subsection (d)(i) above (hereafter referred to as "remote self-supply of Station Power"), Market Seller shall use and pay for transmission service for the transmission of energy in an amount equal to the facility's negative net output from Market Seller's generation facility(ies) having positive net output. Unless the Market Seller makes other arrangements with Transmission Provider in advance, such transmission service shall be provided under Part II of the PJM Tariff and shall be charged the hourly rate under Schedule 8 of the PJM Tariff for Non-Firm Point-to-Point Transmission Service with an election to pay congestion charges, provided, however, that no reservation shall be necessary for such transmission service and the terms and charges under Schedules 1, 1A, 2 through 6, 9 and 10 of the PJM Tariff shall not apply to such service. The amount of energy that a Market Seller transmits in conjunction with remote self-supply of Station Power will not be affected by any other sales, purchases, or transmission of capacity or energy by or for such Market Seller under any other provisions of the PJM Tariff.

(iii) A Market Seller may self-supply Station Power from its generation facilities located outside of the PJM Region during any month only if such generation facilities in fact run during such month and Market Seller separately has reserved transmission service and scheduled delivery of the energy from such resource in advance into the PJM Region.

1.7.11 Emergencies.

(a) The Office of the Interconnection, with the assistance of the Members' dispatchers as it may request, shall be responsible for monitoring the operation of the PJM Region, for declaring the existence of an Emergency, and for directing the operations of Market Participants as necessary to manage, alleviate or end an Emergency. The standards, policies and procedures of the Office of the Interconnection for declaring the existence of an Emergency, including but not limited to a Minimum Generation Emergency, and for managing, alleviating or ending an Emergency, shall apply to all Members on a non-discriminatory basis. Actions by the Office of the Interconnection and the Market Participants shall be carried out in accordance with

this Agreement, the NERC Operating Policies, Applicable Regional Reliability Council reliability principles and standards, Good Utility Practice, and the PJM Manuals. A declaration that an Emergency exists or is likely to exist by the Office of the Interconnection shall be binding on all Market Participants until the Office of the Interconnection announces that the actual or threatened Emergency no longer exists. Consistent with existing contracts, all Market Participants shall comply with all directions from the Office of the Interconnection for the purpose of managing, alleviating or ending an Emergency. The Market Participants shall authorize the Office of the Interconnection and PJMSettlement to purchase or sell energy on their behalf to meet an Emergency, and otherwise to implement agreements with other Control Areas interconnected with the PJM Region for the mutual provision of service to meet an Emergency, in accordance with this Agreement.

(b) To the extent load must be shed to alleviate an Emergency in a Control Zone, the Office of the Interconnection shall, to the maximum extent practicable, direct the shedding of load within such Control Zone. The Office of the Interconnection may shed load in one Control Zone to alleviate an Emergency in another Control Zone under its control only as necessary after having first shed load to the maximum extent practicable in the Control Zone experiencing the Emergency and only to the extent that PJM supports other control areas (not under its control) in those situations where load shedding would be necessary, such as to prevent isolation of facilities within the Eastern Interconnection, to prevent voltage collapse, or to restore system frequency following a system collapse; provided, however, that the Office of the Interconnection may not order a manual load dump in a Control Zone solely to address capacity deficiencies in another Control Zone. This section shall be implemented consistent with the North American Electric Reliability Council and applicable reliability council standards.

1.7.12 Fees and Charges.

Each Market Participant, except for Special Members, shall pay all fees and charges of the Office of the Interconnection for operation of the PJM Interchange Energy Market as determined by and allocated to the Market Participant by the Office of the Interconnection in accordance with Schedule 3.

1.7.13 Relationship to the PJM Region.

The PJM Interchange Energy Market operates within and subject to the requirements for the operation of the PJM Region.

1.7.14 PJM Manuals.

The Office of the Interconnection shall be responsible for maintaining, updating, and promulgating the PJM Manuals as they relate to the operation of the PJM Interchange Energy Market. The PJM Manuals, as they relate to the operation of the PJM Interchange Energy Market, shall conform and comply with this Agreement, NERC operating policies, and Applicable Regional Reliability Council reliability principles, guidelines and standards, and shall be designed to facilitate administration of an efficient energy market within industry reliability standards and the physical capabilities of the PJM Region.

1.7.15 Corrective Action.

Consistent with Good Utility Practice, the Office of the Interconnection shall be authorized to direct or coordinate corrective action, whether or not specified in the PJM Manuals, as necessary to alleviate unusual conditions that threaten the integrity or reliability of the PJM Region, or the regional power system.

1.7.16 Recording.

Subject to the requirements of applicable State or federal law, all voice communications with the Office of the Interconnection Control Center may be recorded by the Office of the Interconnection and any Market Participant communicating with the Office of the Interconnection Control Center, and each Market Participant hereby consents to such recording.

1.7.17 Operating Reserves.

(a) The following procedures shall apply to any generation unit subject to the dispatch of the Office of the Interconnection for which construction commenced before July 9, 1996, or any Demand Resource subject to the dispatch of the Office of the Interconnection.

(b) The Office of the Interconnection shall schedule to the Operating Reserve and load-following objectives of the Control Zones of the PJM Region and the PJM Interchange Energy Market in scheduling generation resources and/or Demand Resources pursuant to this Schedule. A table of Operating Reserve objectives for each Control Zone is calculated and published annually in the PJM Manuals. Reserve levels are probabilistically determined based on the season's historical load forecasting error and forced outage rates.

(c) Nuclear generation resources shall not be eligible for Operating Reserve payments unless: 1) the Office of the Interconnection directs such resources to reduce output, in which case, such units shall be compensated in accordance with section 3.2.3(f) of this Schedule; or 2) the resource submits a request for a risk premium to the Market Monitoring Unit under the procedures specified in Section II.B of Attachment M - Appendix. A nuclear generation resource (i) must submit a risk premium consistent with its agreement under such process, or, (ii) if it has not agreed with the Market Monitoring Unit on an appropriate risk premium, may submit its own determination of an appropriate risk premium to the Office of the Interconnection, subject to acceptance by the Office of the Interconnection, with or without prior approval from the Commission.

(d) PJMSettlement shall be the Counterparty to the purchases and sales of Operating Reserve in the PJM Interchange Energy Market.

1.7.18 Regulation.

(a) Regulation to meet the Regulation objective of each Regulation Zone shall be supplied from generation resources and/or Demand Resources located within the metered

electrical boundaries of such Regulation Zone. Generating Market Buyers, and Market Sellers offering Regulation, shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the PJM Manuals.

(b) The Office of the Interconnection shall obtain and maintain for each Regulation Zone an amount of Regulation equal to the Regulation objective for such Regulation Zone as specified in the PJM Manuals.

(c) The Regulation range of a generation unit or Demand Resource shall be at least twice the amount of Regulation assigned as described in the PJM Manuals.

(d) A ~~generation unit~~resource capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced by at least twice the amount of the Regulation provided with consideration of ~~. T~~the ~~amount of~~ Regulation ~~provided by a generation unit shall serve to redefine the Normal Minimum Generation and Normal Maximum Generation energy~~ limits of that ~~generation unit~~resource~~, in that the amount of Regulation shall be added to the generation unit's Normal Minimum Generation energy limit, and subtracted from its Normal Maximum Generation energy limit~~ as specified in the PJM Manuals.

(e) Qualified Regulation must satisfy the measurement and verification tests described in the PJM Manuals.

1.7.19 Ramping.

A generator dispatched by the Office of the Interconnection pursuant to a control signal appropriate to increase or decrease the generator's megawatt output level shall be able to change output at the ramping rate specified in the Offer Data submitted to the Office of the Interconnection for that generator.

1.7.19A Synchronized Reserve.

(a) Synchronized Reserve shall be supplied from generation resources and/or Demand Resources located within the metered boundaries of the PJM Region. Generating Market Buyers, and Market Sellers offering Synchronized Reserve shall comply with applicable standards and requirements for Synchronized Reserve capability and dispatch specified in the PJM Manuals

(b) The Office of the Interconnection shall obtain and maintain for each ~~*Synchronized*~~ Reserve Zone an amount of *Primary and* Synchronized Reserve equal to the *respective Primary and* Synchronized Reserve objectives for such ~~*Synchronized*~~ Reserve Zone, as specified in the PJM Manuals.

(c) The Synchronized Reserve capability of a generation resource and Demand Resource shall be the increase in energy output or load reduction achievable by the generation resource and Demand Resource within a continuous 10-minute period.

(d) A generation unit capable of automatic energy dispatch that also is providing Synchronized Reserve shall have its energy dispatch range reduced by the amount of the Synchronized Reserve provided. The amount of Synchronized Reserve provided by a generation unit shall serve to redefine the Normal Maximum Generation energy limit of that generation unit in that the amount of Synchronized Reserve provided shall be subtracted from its Normal Maximum Generation energy limit.

1.7.19A.01 Non-Synchronized Reserve.

(a) Non-Synchronized Reserve shall be supplied from generation resources and/or Demand Resources located within the metered boundaries of the PJM Region. Generating Market Buyers and Market Sellers offering Non-Synchronized Reserve shall comply with applicable standards and requirements for Non-Synchronized Reserve capability and dispatch specified in the PJM Manuals.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone an amount of Non-Synchronized Reserve such that the sum of the Synchronized Reserve and Non-Synchronized Reserve meets the Primary Reserve objective for such Reserve Zone, as specified in the PJM Manuals.

(c) The Non-Synchronized Reserve capability of a generation resource and Demand Resource shall be the increase in energy output or load reduction achievable by the generation resource and Demand Resource within a continuous 10-minute period provided that the resource is not synchronized to the system at the initiation of the response.

1.7.19B Bilateral Transactions Regarding Regulation, Synchronized Reserve and Day-ahead Scheduling Reserves.

(a) In addition to transactions in the Regulation market, Synchronized Reserve market, and Day-ahead Scheduling Reserves Market, Market Participants may enter into bilateral contracts for the purchase or sale of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from each other or any other entity. Such bilateral contracts shall be for the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its eMarket tools.

(b) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to a Market Participant in the PJM Region, title to the product that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and any further transactions associated with such products or further sale of such Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves in the markets for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves, respectively, shall be transacted by the buyer under the bilateral contract. In no event shall the purchase and sale of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves between Market Participants under a bilateral contract constitute a

transaction in PJM's markets for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves, or otherwise be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

(c) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the amounts of such reported transactions to amounts reflecting the expected requirements for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves of the buyer pursuant to such bilateral contracts.

(d) All payments and related charges for the Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by 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 a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

(e) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any purchases by the seller under the bilateral contract in the markets for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves used to meet the bilateral contract seller's obligation to deliver Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new eMarket reporting by the Market Participant and (ii) terminate all of the Market Participant's reporting of eMarkets schedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the reported eMarkets schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection.

(f) Market Participants shall purchase Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves from PJM's markets for Regulation, Synchronized Reserve, Day-ahead Scheduling Reserves, in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason, with respect to all bilateral transactions that contemplate the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from a Market Participant.

1.7.20 Communication and Operating Requirements.

(a) Market Participants. Each Market Participant shall have, or shall arrange to have, its transactions in the PJM Interchange Energy Market subject to control by a Market Operations Center, with staffing and communications systems capable of real-time communication with the Office of the Interconnection during normal and Emergency conditions and of control of the Market Participant's relevant load or facilities sufficient to meet the requirements of the Market Participant's transactions with the PJM Interchange Energy Market, including but not limited to the following requirements as applicable.

(b) Market Sellers selling from generation resources and/or Demand Resources within the PJM Region shall: report to the Office of the Interconnection sources of energy available for operation; supply to the Office of the Interconnection all applicable Offer Data; report to the Office of the Interconnection generation resources and Demand Resources that are self-scheduled; with respect to generation resources, report to the Office of the Interconnection bilateral sales transactions to buyers not within the PJM Region; confirm to the Office of the Interconnection bilateral sales to Market Buyers within the PJM Region; respond to the Office of the Interconnection's directives to start, shutdown or change output levels of generation units, or change scheduled voltages or reactive output levels of generation units, or reduce load from Demand Resources; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, generating equipment and Demand Resources are operated with control equipment functioning as specified in the PJM Manuals.

(c) Market Sellers selling from generation resources outside the PJM Region shall: provide to the Office of the Interconnection all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to Office of the Interconnection directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the Market Seller's Control Area.

(d) Market Participants that are Load Serving Entities or purchasing on behalf of Load Serving Entities shall: respond to Office of the Interconnection directives for load management steps; report to the Office of the Interconnection Generation Capacity Resources to satisfy capacity obligations that are available for pool operation; report to the Office of the Interconnection all bilateral purchase transactions; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(e) Market Participants that are not Load Serving Entities or purchasing on behalf of Load Serving Entities shall: provide to the Office of the Interconnection requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the PJM Interchange Energy Market, along with Dispatch Rate levels above which it does not desire to purchase; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(f) Economic Load Response Participants are responsible for maintaining demand reduction information, including the amount and price at which demand may be reduced. The Economic Load Response Participant shall provide this information to the Office of the Interconnection by posting it on the Load Response Program Registration link of the PJM website as required by the PJM Manuals. The Economic Load Response Participant shall notify

the Office of the Interconnection of a demand reduction concurrent with, or prior to, the beginning of such demand reduction in accordance with the PJM Manuals. In the event that an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer that would affect a relevant Customer Baseline Load as required by the PJM Manuals.

(g) PRD Providers shall be responsible for ensuring automated reductions to their Price Responsive Demand in response to price in accordance with their PRD Curves submitted to the Office of the Interconnection.

1.10 Scheduling.

1.10.1 General.

(a) The Office of the Interconnection shall administer scheduling processes to implement a Day-ahead Energy Market and a Real-time Energy Market. PJMSettlement shall be the Counterparty to the purchases and sales of energy that clear the Day-ahead Energy Market and the Real-time Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a Generating Market Buyer's self-schedule or self-supply of its generation resources up to that Generating Market Buyer's Equivalent Load.

(b) The Day-ahead Energy Market shall enable Market Participants to purchase and sell energy through the PJM Interchange Energy Market at Day-ahead Prices and enable Transmission Customers to reserve transmission service with Transmission Congestion Charges and Transmission Loss Charges based on locational differences in Day-ahead Prices. Up-To Congestion transactions submitted in the Day-ahead Energy Market shall not require transmission service and Transmission Customers shall not reserve transmission service for such transactions. Market Participants whose purchases and sales, and Transmission Customers whose transmission uses are scheduled in the Day-ahead Energy Market, shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, at the applicable Day-ahead Prices for the amounts scheduled.

(c) In the Real-time Energy Market, Market Participants that deviate from the amounts of energy purchases or sales, or Transmission Customers that deviate from the transmission uses, scheduled in the Day-ahead Energy Market shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling shall be conducted as specified below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM Manuals.

1.10.1A Day-~~A~~a~~a~~head Energy Market Scheduling.

The following actions shall occur not later than 12:00 noon on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the Office of the Interconnection in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Schedule.

(a) Each Market Participant may submit to the Office of the Interconnection specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the PJM Manuals. Each Market Buyer shall inform the Office of the Interconnection of the prices, if any, at which it desires not to include its load in the Day-ahead Energy Market rather than pay the Day-ahead Price. PRD Providers that have committed Price Responsive Demand in accordance with the Reliability Assurance Agreement shall submit to the Office of the Interconnection, in accordance with procedures specified in the PJM Manuals, any desired updates to their previously submitted PRD Curves, provided that such updates are consistent with their Price Responsive Demand commitments, and provided further that PRD Providers that are not Load-Serving Entities for the Price Responsive Demand load at issue may only submit PRD Curves for the Real-time Energy Market. Price Responsive Demand that has been committed in accordance with the Reliability Assurance Agreement shall be presumed available for the next Operating Day in accordance with the most recently submitted PRD Curve unless the PRD Curve is updated to indicate otherwise. PRD Providers may also submit PRD Curves for any Price Responsive Demand that is not committed in accordance with the Reliability Assurance Agreement; provided that PRD Providers that are not Load-Serving Entities for the Price Responsive Demand load at issue may only submit PRD Curves for the Real-time Energy Market. All PRD Curves shall be on a PRD Substation basis, and shall specify the maximum time period required to implement load reductions.

(b) Each Generating Market Buyer shall submit to the Office of the Interconnection: (i) hourly schedules for resource increments, including hydropower units, self-scheduled by the Market Buyer to meet its Equivalent Load; and (ii) the Dispatch Rate at which each such self-scheduled resource will disconnect or reduce output, or confirmation of the Market Buyer's intent not to reduce output.

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

Office of the Interconnection if the parties to the transaction are not willing to incur Transmission Congestion Charges in the Real-time Energy Market in order to complete any such scheduled bilateral transaction. Scheduling of bilateral transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

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

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

iii) In addition to the foregoing schedules for bilateral transactions, Market Participants shall submit confirmations of each scheduled bilateral transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(d) Market Sellers wishing to sell into the Day-ahead Energy Market shall submit offers for the supply of energy (including energy from hydropower units), demand reductions, Regulation, Operating Reserves or other services for the following Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Attachment DD of the PJM Tariff, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. *Any offer not designated as a Maximum Emergency Offer shall be considered available for scheduling and dispatch under both Emergency and non-Emergency conditions. Offers may only be designated as Maximum Emergency Offers to the extent that the Generation Capacity Resource falls into at least one of the following categories:*

i) Environmental limits. If the resource has a limit on its run hours imposed by a federal, state or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited to operating only during declared PJM capacity emergencies by a governmental authority.

ii) Fuel limits. If physical events beyond the control of the resource owner result in the temporary interruption of fuel supply and there is limited on-site fuel storage. A fuel supplier's exercise of a contractual right to interrupt supply or delivery

under an interruptible service agreement shall not qualify as an event beyond the control of the resource owner.

iii) Temporary emergency conditions at the unit. If temporary emergency physical conditions at the resource significantly limit its availability.

iv) Temporary megawatt additions. If a resource can provide additional megawatts on a temporary basis by oil topping, boiler over-pressure, or similar techniques and such megawatts are not ordinarily otherwise available.

The submission of offers for resource increments that have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, and PJM Manuals, as applicable. Energy offered from generation resources that have not cleared a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region. The foregoing offers:

i) Shall specify the Generation Capacity Resource or Demand Resource and energy or demand reduction amount, respectively, for each hour in the offer period, and the minimum run time for generation resources and minimum down time for Demand Resources;

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

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

iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;

v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with a second schedule applicable if accepted after the foregoing deadline;

vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer, which offer shall remain open through the Operating Day for which the offer is submitted;

vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day; and

viii) Shall not exceed an energy offer price of $1,000/megawatt-*hour for all generation resources and Demand Resources that have cleared a Base Residual Auction or an Incremental Auction.*

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation that shall specify the megawatt of Regulation being offered, which must equal or exceed 0.1 megawatts, the Regulation Zone for which such regulation is offered, the price of the capability offer in dollars per MW~~h~~, the price of the performance offer in Dollars per change in MW, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the resource's opportunity costs. The ~~price of the offer~~ total of the performance offer multiplied by the historical average mileage used in the market clearing plus the capability offer shall not exceed $100 per MWh in the case of Regulation offered for all Regulation Zones. In addition to any market-based offer for Regulation, the Market Seller also shall submit a cost-based offer. A cost-based offer must be in the form specified in the PJM Manuals and consist of the following components as well as any other components specified in the PJM Manuals:

i. The costs (in $/MW) of the fuel cost increase due to the heat rate increase resulting from operating a unit at lower megawatt output incurred from the provision of Regulation;

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

iii. An adder of up to $12.00 per megawatt of Regulation provided applied to the capability offer.

Qualified Regulation capability must satisfy the measurement and verification tests specified in the PJM Manuals.

(f) Each Market Seller owning or controlling the output of a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative shall submit a forecast of the availability of each such Generation Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with start-up and no-load fees, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours.

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

(h) The Office of the Interconnection shall post the total hourly loads scheduled in the Day-ahead Energy Market, as well as, its estimate of the combined hourly load of the Market Buyers for the next four days, and peak load forecasts for an additional three days.

(i) Except for Economic Load Response Participants, all Market Participants may submit Increment Bids and/or Decrement Bids that apply to the Day-ahead Energy Market only. Such bids must comply with the requirements set forth in the PJM Manuals and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-ahead Energy Market. The Office of the Interconnection may require that a market participant shall not submit in excess of 3000 bid/offer segments in the Day-ahead Energy Market, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to 10:00 a.m. EPT on the day that the Day-ahead Energy Market will clear. For purposes of this provision, a bid/offer segment is each pairing of price and megawatt quantity submitted as part of an Increment Bid or Decrement Bid.

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

(k) An Economic Load Response Participant that wishes to participate in the Day-ahead Energy Market by reducing demand shall submit an offer to reduce demand to the Office of the Interconnection. The offer must equal or exceed 0.1 megawatts, and the offer shall specify: (i) the amount of the offered curtailment in minimum increments of .1 megawatts: (ii) the Day-ahead Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, start-up costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum of number of contiguous hours for which the load reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs).

(l) Market Sellers owning or controlling the output of a Demand Resource that was committed in an FRR Capacity Plan, self-supplied or offered and cleared in the Base Residual Auction or one of the Incremental Auctions, or owning or controlling the output of an ILR resource which was certified as specified in Attachment DD of the PJM Tariff, may submit

demand reduction bids for the available load reduction capability of the Demand Resource or ILR resource. The submission of demand reduction bids for resource increments that have not cleared in the Base Residual Auction or in one of the Incremental Auctions, or for ILR resources that were not certified, or were not committed in an FRR Capacity Plan, shall be optional, but any such bids must contain the information specified in the PJM Economic Load Response Program to be included in such bids. A Demand Resource that was committed in an FRR Capacity ~~p~~Plan, self-supplied or offered and cleared in a Base Residual Auction or an Incremental Auction may submit a demand reduction bid in the Day-ahead Energy Market as specified in the Economic Load Response Program, provided however, that in the event of an Emergency, PJM shall require Demand Resources and ILR resources to reduce load notwithstanding that the Zonal LMP at the time such Emergency is declared is below the price identified in the demand reduction bid.

(m) Market Sellers that wish to make Day-ahead Scheduling Reserves Resources available to sell Day-ahead Scheduling Reserves shall submit offers, each of which must equal or exceed 0.1 megawatts, in the Day-ahead Scheduling Reserves Market specifying: 1) the price of the offer in dollars per megawatt hour; and 2) such other information specified by the Office of the Interconnection as may be necessary to determine any relevant opportunity costs for the resource(s). The foregoing notwithstanding, to qualify to submit offers pursuant to this section, the Day-ahead Scheduling Reserves Resources shall submit energy offers in the Day-ahead Energy Market including start-up and shut-down costs for generation resource and Demand Resources, respectively, and all generation resources that are capable of providing Day-ahead Scheduling Reserves that a particular resource can provide that service. The MW quantity of Day-~~A~~ahead Scheduling Reserves that a particular resource can provide in a given hour will be determined based on the energy Offer Data submitted in the Day-ahead Energy Market, as detailed in the PJM Manuals.

1.10.2 Pool-~~S~~scheduled Resources.

Pool-scheduled resources are those resources for which Market Participants submitted offers to sell energy in the Day-ahead Energy Market and offers to reduce demand in the Day-ahead Energy Market, which the Office of the Interconnection scheduled in the Day-ahead Energy Market as well as generators committed by the Office of the Interconnection subsequent to the Day-ahead Energy Market. Such resources shall be committed to provide energy in the real-time dispatch unless the schedules for such units are revised pursuant to Sections 1.10.9 or 1.11. Pool-scheduled resources shall be governed by the following principles and procedures.

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, start-up, no-load and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in Section 1.10.1A.

(b) A resource that is scheduled by a Market Participant to support a bilateral sale, or that is self-scheduled by a Generating Market Buyer, shall not be selected by the Office of the Interconnection as a pool-scheduled resource except in an Emergency.

(c) Market Sellers offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the Office of the Interconnection that is sufficient to enable the Office of the Interconnection to determine the available operating hours of such facilities.

(d) The Market Seller of a resource selected as a pool-scheduled resource shall receive payments or credits for energy, demand reductions or related services, or for start-up and no-load fees, from the Office of the Interconnection on behalf of the Market Buyers in accordance with Section 3 of this Schedule 1. Alternatively, the Market Seller shall receive, in lieu of start-up and no-load fees, its actual costs incurred, if any, up to a cap of the resource's start-up cost, if the Office of the Interconnection cancels its selection of the resource as a pool-scheduled resource and so notifies the Market Seller before the resource is synchronized.

(e) Market Participants shall make available their pool-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone.

(f) Economic Load Response Participants offering to reduce demand shall specify: (i) the amount of the offered curtailment, which offer must equal or exceed 0.1 megawatts, in minimum increments of .1 megawatts; (ii) the real-time Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, shut-down costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum number of contiguous hours for which the load reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Real-time Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs). Economic Load Response Participants offering to reduce demand shall also indicate the hours that the demand reduction is not available.

1.10.3 Self-scheduled Resources.

Self-scheduled resources shall be governed by the following principles and procedures.

(a) Each Generating Market Buyer shall use all reasonable efforts, consistent with Good Utility Practice, not to self-schedule resources in excess of its Equivalent Load.

(b) The offered prices of resources that are self-scheduled, or otherwise not following the dispatch orders of the Office of the Interconnection, shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.

(c) Market Participants shall make available their self-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone, by submitting an offer as to such resources.

(d) A Market Participant self-scheduling a resource in the Day-ahead Energy Market that does not deliver the energy in the Real-time Energy Market, shall replace the energy not

delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

1.10.4 Capacity Resources.

(a) A Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that is selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection. Such a Generation Capacity Resource that does not deliver energy as scheduled shall be deemed to have experienced a Generator Forced Outage to the extent of such energy not delivered. A Market Participant offering such Generation Capacity Resource in the Day-ahead Energy Market shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Energy from a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that has not been scheduled in the Day-ahead Energy Market may be sold on a bilateral basis by the Market Seller, may be self-scheduled, or may be offered for dispatch during the Operating Day in accordance with the procedures specified in this Schedule. Such a Generation Capacity Resource that has not been scheduled in the Day-ahead Energy Market and that has been sold on a bilateral basis must be made available upon request to the Office of the Interconnection for scheduling and dispatch during the Operating Day if the

Office of the Interconnection declares a Maximum Generation Emergency. Any such resource so scheduled and dispatched shall receive the applicable Real-time Price for energy delivered.

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

1.10.5 External Resources.

(a) External Resources may submit offers to the PJM Interchange Energy Market, in accordance with the day-ahead and real-time scheduling processes specified above. An External Resource selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection, and except as specified below shall be compensated on the same basis as other pool-scheduled resources. External Resources that are not capable of dynamic dispatch shall, if selected by the Office of the Interconnection on the basis of the Market Seller's Offer Data, be block loaded on an hourly scheduled basis. Market Sellers shall offer External Resources to the PJM Interchange Energy Market on either a resource-specific or an aggregated resource basis. A Market Participant whose pool-scheduled resource does not deliver the energy scheduled in the Day-ahead Energy Market shall replace such energy not delivered as scheduled in the Day-ahead Energy Market with energy from the PJM Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Offers for External Resources from an aggregation of two or more generating units shall so indicate, and shall specify, in accordance with the Offer Data requirements specified by the Office of the Interconnection: (i) energy prices; (ii) hours of energy availability; (iii) a minimum dispatch level; (iv) a maximum dispatch level; and (v) unless such information has previously been made available to the Office of the Interconnection, sufficient information, as specified in the PJM Manuals, to enable the Office of the Interconnection to model the flow into the PJM Region of any energy from the External Resources scheduled in accordance with the Offer Data.

(c) Offers for External Resources on a resource-specific basis shall specify the resource being offered, along with the information specified in the Offer Data as applicable.

1.10.6 External Market Buyers.

(a) Deliveries to an External Market Buyer not subject to dynamic dispatch by the Office of the Interconnection shall be delivered on a block loaded basis to the bus or busses at the electrical boundaries of the PJM Region, or in such area with respect to an External Market Buyer's load within such area not served by Network Service, at which the energy is delivered to or for the External Market Buyer. External Market Buyers shall be charged (which charge may be positive or negative) at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing bus or busses.

(b) An External Market Buyer's hourly schedules for energy purchased from the PJM Interchange Energy Market shall conform to the ramping and other applicable requirements of the interconnection agreement between the PJM Region and the Control Area to which, whether as an intermediate or final point of delivery, the purchased energy will initially be delivered.

(c) The Office of the Interconnection shall curtail deliveries to an External Market Buyer if necessary to maintain appropriate reserve levels for a Control Zone as defined in the PJM Manuals, or to avoid shedding load in such Control Zone.

1.10.6A Transmission Loading Relief Customers.

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

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

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

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

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

1.10.7 Bilateral Transactions.

Bilateral transactions as to which the parties have notified the Office of the Interconnection by the deadline specified in Section 1.10.1A that they elect not to be included in the Day-ahead Energy Market and that they are not willing to incur Transmission Congestion Charges in the Real-time Energy Market shall be curtailed by the Office of the Interconnection as necessary to reduce or alleviate transmission congestion. Bilateral transactions that were not included in the Day-ahead Energy Market and that are willing to incur congestion charges and bilateral transactions that were accepted in the Day-ahead Energy Market shall continue to be implemented during periods of congestion, except as may be necessary to respond to Emergencies.

1.10.8 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers and PRD Curves properly submitted by Load Serving Entities for the Price Responsive Demand loads they serve; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv) the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall

report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) Not earlier than 4:00 p.m. of the day before each Operating Day, or such other deadline as may be specified by the Office of the Interconnection in the PJM Manuals, the Office of the Interconnection shall: (i) post the aggregate Day-ahead Energy Market results; (ii) post the Day-ahead Prices; and (iii) inform the Market Sellers, Market Buyers, and Economic Load Response Participants of their scheduled injections, withdrawals, and demand reductions respectively.

(c) Following posting of the information specified in Section 1.10.8(b), the Office of the Interconnection shall revise its schedule of generation resources to reflect updated projections of load, conditions affecting electric system operations in the PJM Region, the availability of and constraints on limited energy and other resources, transmission constraints, and other relevant factors.

(d) Market Buyers shall pay PJMSettlement and Market Sellers shall be paid by PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the offer that set the Day-ahead Price is positive. Market Buyers shall be paid by PJMSettlement and Market Sellers shall pay PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the offer that set the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Section 3.3A of this Schedule.

(e) If the Office of the Interconnection discovers an error in prices and/or cleared quantities in the Day-ahead Energy Market, Real-time Energy Market, Ancillary Services Markets or Day Ahead Scheduling Reserve Market after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 12:00 p.m. of the second business day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the second business day following the initial publication of the results for the Day-ahead Scheduling Reserve Market and Day-ahead Energy Market.

After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the fifth business day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the fifth business day following the initial publication of the results in the Day-ahead Scheduling Reserve Market and the Day-ahead Energy Market. Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating Day for the Ancillary Services Markets, Day-ahead Energy Market and Real-time Energy Market, and no later than 5:00 p.m. of the tenth calendar day following the initial publication of the results in the Day-ahead Scheduling Reserve Market. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final.

Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced market results are under publicly noticed review by the FERC.

(f) Consistent with Section 18.17.1 of the PJM Operating Agreement, and notwithstanding anything to the contrary in the Operating Agreement or in the PJM Tariff, to allow the tracking of Market Participants' non-aggregated bids and offers over time as required by FERC Order No. 719, the Office of the Interconnection shall post on its Web site the non-aggregated bid data and Offer Data submitted by Market Participants (for participation in the PJM Interchange Energy Market) approximately four months after the bid or offer was submitted to the Office of the Interconnection.

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, a generation rebidding period shall exist from 4:00 p.m. to 6:00 p.m. on the day before each Operating Day. During the rebidding period, Market Participants may submit revisions to generation Offer Data for any generation resource that was not selected as a pool-scheduled resource in the Day-ahead Energy Market. Adjustments to Day-ahead Energy Markets shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 60 minutes prior to the hour in which the adjustment is to take effect, as follows:

i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;

ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or

iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or

iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any start-up fee.

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

(d) An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase in the Day-ahead Energy Market by notifying the Office of the Interconnection of the adjustment in deliveries not later than 60 minutes prior to the hour in which the adjustment is to take effect, but any such adjustment shall not affect the obligation of the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(e) For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section 1.10, the Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules for the hour.

1.11 Dispatch.

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

1.11.1 Resource Output.

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

1.11.2 Operating Basis.

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

1.11.3 Pool-dispatched Resources.

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

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

1.11.3A Maximum Generation Emergency.

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

1.11.4 Regulation.

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

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

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

1.11.4A Synchronized Reserve.

(a) A Market Buyer may satisfy its Synchronized Reserve -Oobligation from its own generation resources and/or Demand Resources capable of providing Synchronized Reserve, by contractual arrangements with other Market Participants able to provide Synchronized Reserve,

or by purchases from the PJM Synchronized Reserve Market at the rates set forth in Section 3.2.3A. PJMSettlement shall be the Counterparty to the purchases and sales of Synchronized Reserve in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Synchronized Reserve Obligation.

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

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

1.11.4B Non-Synchronized Reserve.

(a) A Market Buyer may satisfy its Non-Synchronized Reserve Obligation from its own generation resources and/or Demand Resources capable of providing Non-Synchronized Reserve, by contractual arrangements with other Market Participants able to provide Non-Synchronized Reserve, or by purchases from the PJM Non-Synchronized Reserve Market at the rates set forth in Section 3.2.3A.001.

(b) The Office of the Interconnection shall obtain Non-Synchronized Reserve from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Demand Resources as needed to ensure the Primary Reserve requirement of each Reserve Zone of the PJM Region not otherwise satisfied by the Market Buyers. Resources offering to sell Non-Synchronized Reserve shall be selected to provide Non-Synchronized Reserve on the basis of each generation resource's and/or Demand Resource's estimated unit specific opportunity cost of the resource providing Non-Synchronized Reserve, and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Synchronized Reserve and other ancillary services. Estimated unit specific opportunity costs for generation resources shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) ~~the absolute value of~~ the difference between the Locational marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Non-Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources will be zero.

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

1.11.5 PJM Open Access Same-time Information System.

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

2.2 General.

The Office of the Interconnection shall determine the least cost security-constrained dispatch, which is the least costly means of serving load *and meeting reserve requirements* at different locations in the PJM Region based on actual operating conditions existing on the power grid (including transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6) and on the prices at which Market Sellers have offered to supply energy and offers by Economic Load Response Participants to reduce demand that qualify to set Locational Marginal Prices in the PJM Interchange Energy Market. Locational Marginal Prices for the generation and load busses in the PJM Region, including interconnections with other Control Areas, will be calculated based on the actual economic dispatch and the prices of energy and demand reduction offers. The process for the determination of Locational Marginal Prices shall be as follows:

(a) To determine actual operating conditions on the power grid in the PJM Region, the Office of the Interconnection shall use a computer model of the interconnected grid that uses available metered inputs regarding generator output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network. The computer model employed for this purpose, referred to as the State Estimator program, is a standard industry tool and is described in Section 2.3 below. It will be used to obtain information regarding the output of generation supplying energy to the PJM Region, loads at busses in the PJM Region, transmission losses, and power flows on binding transmission constraints for use in the calculation of Locational Marginal Prices. Additional information used in the calculation, including Dispatch Rates and real time schedules for external transactions between PJM and other Control Areas and dispatch and pricing information from entities with whom PJM has executed a joint operating agreement, will be obtained from the Office of the Interconnection's dispatchers.

(b) Using the prices at which energy is offered by Market Sellers and demand reductions are offered by Economic Load Response Participants to the PJM Interchange Energy Market, the Office of the Interconnection shall determine the offers of energy and demand reductions that will be considered in the calculation of Locational Marginal Prices. As described in Section 2.4 below, every qualified offer for demand reduction and of energy by a Market Seller from resources that are ~~*following economic dispatch instructions of*~~*dispatched by* the Office of the Interconnection will be utilized in the calculation of Locational Marginal Prices, including, without limitation, qualified offers from Economic Load Response Participants in either the Day-Ahead or Real-Time Energy Markets that satisfy the Net Benefits Test. Offers of ~~*demand reduction*~~*economic load response* from Demand Resources in the Real-time Energy Market will not be eligible to set Locational Marginal Prices, unless metered directly by the Office of the Interconnection. *Offers of Full Program Option resources in the Emergency Load Response Program are eligible to set real time Locational Marginal Prices when the Office of the Interconnection has implemented Emergency procedures and such resources are required to reduce demand in the PJM Region, so long as sufficient data is available to accurately model the resources.*

(c) Based on the system conditions on the PJM power grid, determined as described in (a), and the eligible energy and demand reduction offers, determined as described in (b), the Office of the Interconnection shall determine the least costly means of obtaining energy to serve the next increment of load at each bus in the PJM Region, in the manner described in Section 2.5 below. The result of that calculation shall be a set of Locational Marginal Prices based on the system conditions at the time.

2.3 Determination of System Conditions Using the State Estimator.

Power system operations, including, but not limited to, the determination of the least costly means of serving load *and meeting reserve requirements*, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In calculating Locational Marginal Prices, the Office of the Interconnection shall obtain a complete and consistent description of conditions on the electric network in the PJM Region by using the most recent power flow solution produced by the State Estimator *program and utilized in the PJM dispatch algorithm*, which *State Estimator program* is also used by the Office of the Interconnection for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available real-time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at busses for which real-time information is unavailable. The Office of the Interconnection shall obtain a State Estimator solution every five minutes, which shall provide the megawatt output of generators and the loads at busses in the PJM Region, transmission line losses, and actual flows or loadings on constrained transmission facilities. External transactions between PJM and other Control Areas shall be included in the Locational Marginal Price calculation on the basis of the real time transaction schedules implemented by the Office of the Interconnection's dispatcher.

2.4 Determination of Energy Offers Used in Calculating Real-time Prices.

(a) During the Operating Day, real-time Locational Marginal Prices derived in accordance with this Section shall be determined every five minutes and integrated hourly values of such determinations shall be the basis of sales and purchases of energy in the Real-time Energy Market and of Transmission Congestion Charges under the PJM Tariff not covered by the Day-ahead Energy Market.

(b) To determine the energy offers submitted to the PJM Interchange Energy Market that shall be used during the Operating Day to calculate the Real-time Prices, the Office of the Interconnection shall determine *the applicable marginal energy offer of the* ~~which~~ resources *being dispatched by the Office of the Interconnection* ~~are following its economic dispatch instructions~~. A resource ~~will be considered to be following economic dispatch instructions and~~ shall be included in the calculation of Real-time Prices if ~~:~~

~~*i)* the~~ the applicable *marginal energy offer of the* ~~price bid by a Market Seller for energy from the~~ resource *being dispatched by the Office of the Interconnection* is less than or equal to the Dispatch Rate for the area of the PJM Region in which the resource is located~~.; or~~

~~ii) the resource is specifically requested to operate by the Office of the Interconnection's dispatcher.~~

(c) In determining whether a resource satisfies the condition described in (b), the Office of the Interconnection will determine the ~~*bid price associated with an*~~ *applicable marginal* energy offer by comparing the ~~*actual*~~ *requested* megawatt output of the resource with the Market Seller's offer price curve. ~~*Because of practical generator response limitations, a resource whose megawatt output is not ten percent more than the megawatt level specified on the offer price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but t*~~*T*he *applicable marginal* energy ~~*price*~~ offer used in the calculation of Real-time Prices shall not exceed the applicable Dispatch Rate. Units that must be run for local area protection shall not be considered in the calculation of Real-time Prices.

2.5 Calculation of Real-time Prices.

(a) The Office of the Interconnection shall determine the least costly means of obtaining energy to serve the next increment of load (taking account of any applicable and available load reductions indicated on PRD Curves properly submitted by any PRD Provider) at each bus in the PJM Region represented in the State Estimator and each Interface Pricing Point between PJM and an adjacent Control Area, based on the system conditions described by the most recent power flow solution produced by the State Estimator program *and utilized in the PJM dispatch algorithm* and the energy offers that are the basis for the Day-ahead Energy Market, or that are determined to be eligible for consideration under Section 2.4 in connection with the real-time dispatch, as applicable. This calculation shall be made by applying ~~an incremental linear optimization method to minimize energy costs~~ *a real-time joint optimization of energy and reserves,* given actual system conditions, a set of energy offers, *a set of reserve offers, a set of Reserve Penalty Factors,* and any binding transmission constraints that may exist. In performing this calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a generation resource or decrease an increment of energy being consumed by a Demand Resource, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses. *The real-time Locational Marginal Prices at a bus shall be determined through the joint optimization based on the lowest marginal cost to serve the next increment of load at the bus taking into account the applicable reserve requirements, unit resource constraints, transmission constraints and marginal loss impact.* ~~*The energy offer or offers that can serve an increment of load at a bus at the lowest cost, calculated in this manner, shall determine the Real-time Price at that bus.*~~

(*b*) *If all reserve requirements in every modeled Reserve Zone can be met at prices less than or equal to the Reserve Penalty Factors for both the Synchronized Reserves and Non-synchronized Reserves, real-time Locational Marginal Prices shall be calculated as described in Section 2.5(a) above and no Reserve Penalty Factor shall apply beyond the normal lost opportunity costs incurred by the reserve requirements. When a reserve requirement cannot be met at a price less than or equal to the Reserve Penalty Factors associated with a Reserve Zone, the real-time Locational Marginal Prices shall be calculated by incorporating the applicable Reserve Penalty Factor for the deficient reserve product as the lost opportunity cost impact of the deficient reserve requirement, and the components of Locational Marginal Prices referenced in Section 2.5(a) above shall be calculated accordingly.*

(c) If the Office of the Interconnection has initiated in a Reserve Zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as

described in the PJM Manuals, Locational Marginal Prices for that Reserve Zone will be calculated including the Reserve Penalty Factors of all reserve products in that Reserve Zone.

(~~b~~*d*) During the Operating Day, the calculation set forth in (a) shall be performed every five minutes, using the Office of the Interconnection's Locational Marginal Price program, producing a set of Real-time Prices based on system conditions during the preceding interval. The prices produced at five-minute intervals during an hour will be integrated to determine the Real-time Prices for that hour.

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 ~~at~~: (i) the capability Regulation market-clearing price determined in accordance with subsection (~~c~~g) of this section; ~~, plus~~ the amounts, if any, described in subsection (~~f~~e) of this section; and (iii) the Internal Market Buyer's pro rata share of any performance credits paid to regulating resources calculated in accordance with subsection (f) of this section.

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

(c) The 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 (f) 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 ~~*The 5-minute clearing prices are calculated as the* highest sum of a resource's Regulation offer plus its *estimated*~~ unit-specific opportunity costs, *during the 5-minute period* determined as described in subsection (d) below from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.3.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation *5-minute* ~~market~~ clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour shall be equal to ~~*the sum of the unit-specific opportunity costs (i) incurred during the hour in which the obligation is fulfilled, plus costs (ii) associated with uneconomic operation during the hour preceding the initial regulating hour ("preceding*~~

~~*shoulder hour"), plus costs (iii) associated with uneconomic operation during the hour after the final regulating hour ("following shoulder hour").*~~

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

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

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

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

~~(e) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's Regulation signals from the generation resource's expected output level if it had been dispatched~~

~~in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.~~

~~The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.~~

~~The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the following shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the following shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the following shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.~~

(~~f~~e) 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.

(f) 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 (f) 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 capacity Regulation market-clearing price.

(g) 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.

(h) 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.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to section 1.10.1A(e) of this Schedule. A Regulation supplier fails the three-pivotal supplier test in any hour in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

(b) For the purposes of conducting the three-pivotal supplier test pursuant to this section, the following applies:

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region for which the 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.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Section 3.2.3A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the Day-ahead Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load fees and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve credits,

identified as RA Credits for Reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

(c) The sum of the foregoing credits calculated in accordance with Section 3.2.3(b) plus any unallocated charges from Section 3.2.3(h) and 5.1.7 and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of Operating Reserves in the Day-ahead Energy Market.

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following segments: 1) the greater of their day-ahead schedules or minimum run time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or minimum run time (minimum down time for Demand Resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time (minimum down time for Demand Resources) and Segment 2 will include the remainder of the contiguous hours when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

Credits received pursuant to this section shall be equal to the positive difference between a resource's total offered price for start-up (shutdown costs for Demand Resources) and no-load fees and energy, determined on the basis of the resource's scheduled output, and the total value of the resource's energy as determined by the Real-time Energy Market and the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for segment 2 shall exclude start up (shutdown costs for Demand Resources) costs for generation resources.

Except as provided in Section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to Section 3.2.3(b) plus the resource's opportunity cost and less any amounts credited for Synchronized Reserve in excess of the Synchronized Reserve offer plus the resource's opportunity cost and less any amounts credited for providing Reactive Services as specified in Section 3.2.3.B, and less any amounts for Day-ahead Scheduling Reserve in excess of the Day-ahead Scheduling Reserve offer plus the resource's opportunity cost, shall be credited to the Market Seller.

Synchronized Reserve, *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 {(LMPDMW - AG) x (URTLMP – UB)}, where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

AG equals the actual hourly integrated output of the unit;

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

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

where URTLMP - UB shall not be negative.

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

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described above for a steam unit or combined cycle unit operating in combined cycle mode.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the Market Seller shall be

credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG, or (ii) {(URTLMP – UB) x DAG where:

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

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

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

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

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

(f-2) A Market Seller's hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Section 1.10.2(d) such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves, plus any redispatch costs incurred in accordance with section 10(a) of this Schedule, shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (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 ~~area~~ region pursuant to Section 1.12.

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~~s~~, as defined in Section 3.2.3(q) of this Schedule, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with Section 3.2.3(q). Deviations at interfaces and hubs shall be associated with the Eastern or Western Region if all the busses that define all interfaces or all hubs are located in the region. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by busses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed in accordance with the following provisions:

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of an Operating Reserve shortage in real-time or where PJM initiates the request for load reductions in real-time in order to avoid an Operating Reserve shortage. ~~*as described in this Schedule, Section 6A, Scarcity Pricing.*~~

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in Section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for ~~of~~ the PJM Region.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside the PJM Region pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared ("Maximum Generation Emergency Alert"); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the Operating Reserves credit otherwise provided by Section 3.2.3.(b) or Section 3.2.3(e) in connection with market-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as "MaxGen Conditions"). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Schedule 2 of the Operating Agreement, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatt hours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any hours required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described in the PJM Manuals. Ramp-limited desired MW values shall be used to determine generation resource real-time deviations from the resource's day-ahead schedules.

The Office of the Interconnection shall calculate a ramp-limited desired MW value for generation resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:

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

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

$$\mathbf{Ramp_Request}_{t} = \left(\mathbf{UDStarget}_{t-1} - \mathbf{AOutput}_{t-1}\right) \Big/ \left(\mathbf{UDSLAtime}_{t-1}\right)$$

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

where:

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

To determine if a 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 <= 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 n 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 to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve charges shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve charges shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve charges shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead

schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region. For the purposes of this section, the Western Region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, *DEOK* transmission Zones, and the Eastern Region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones. The regional balancing Operating Reserve rates shall be determined in accordance with the following provisions:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits in excess of the regional adder rates calculated

pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

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

(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.

3.2.3A Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each ~~*Synchronized*~~ Reserve Zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such ~~*Synchronized*~~ Reserve Zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). An Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts if any, described in subsections (g), (h) and (i) of this section.

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

i) Credits for Synchronized Reserve provided by generation ~~*units*~~ *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; with the exception of those hours in which the Non-Synchronized Reserve Market Clearing Price for the applicable Reserve 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 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 ~~Synchronized~~ Reserve Zone by the Office of the Interconnection ~~*prior to the operating hour and such market-clearing price shall be equal to, from among the generation resources or Demand Resources selected to provide Synchronized Reserve for such Synchronized Reserve Zone, the highest sum of either (i) a generation resource's Synchronized Reserve offer and opportunity cost or (ii) a demand response resource's Synchronized Reserve offe*~~ *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, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve requirement in a Reserve 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, but less than or equal to the sum of the Synchronized Reserve Penalty Factor and the Primary Reserve Penalty Factor for the Reserve Zone. If the Office of the Interconnection has initiated in a Reserve 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.*

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

i. $250/MWh for the 2011/2012 Delivery Year;

ii. $400/MWh for the 2012/2013 Delivery Year;

iii. $550/MWh for the 2013/2014 Delivery Year; and

iv. $850/MWh as of the 2014/2015 Delivery Year.

After June 1, 2014, 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 the Delivery Year(s).

(e) In determining the 5-minute Synchronized Reserve ~~Market Clearing~~ clearing ~~Price~~price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the expected Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

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

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

Seller's Synchronized Reserve Obligation, the remainder of the Tier 1 Synchronized Reserve that is not utilized to fulfill the Seller's obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

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

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

(j) In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled by the owner to provide Tier 2 Synchronized Reserve fails to provide the assigned or self-scheduled amount of Synchronized Reserve in response to an actual Synchronized Reserve Event, *the 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 ~~*Synchronized*~~ Reserve Zone of the PJM Region on which the Synchronized Reserve Obligations, except for the additional obligations set forth in this section, are based shall be reduced by the amount of this shortfall for the applicable three-day period.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l) is the difference between the generation resource's output or the Demand Resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a

Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load Demand Resource's consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity 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 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 for the hour ("Non-Synchronized Reserve Obligation"). 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 (d) of this section, plus the amounts if any, described in paragraphs (g), (h) and (i) 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 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. Opportunity costs for Demand Resources to provide Non-Synchronized Reserves are zero.*

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve 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 serving the next increment of demand for Non-Synchronized Reserve in each Reserve Zone inclusive of opportunity costs associated with meeting the Primary Reserve requirement. When the Primary Reserve requirement in a Reserve 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 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.

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

i. $250/MWh for the 2011/2012 Delivery Year;

ii. $400/MWh for the 2012/2013 Delivery Year;

iii. $550/MWh for the 2013/2014 Delivery Year; and

iv. $850/MWh as of the 2014/2015 Delivery Year.

After June 1, 2014, 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 solely for the purpose of providing Non-Synchronized Reserves shall be equal to the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Non-Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) ~~the absolute value of~~ the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. The opportunity costs for a Demand Resource shall be zero.

(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 absolute value of~~ the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the generation resource) in the PJM Interchange Energy Market. The opportunity costs for a Demand Resource shall be zero.

(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 or a Demand Resource, except for Batch Load Demand Resources covered by Section 3.2.3A(1), 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.

(h) 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 Non-Synchronized Reserve fails to provide the assigned or self-scheduled 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.

(i) 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 megawattts in its offer at the start of a Non-Synchronized Reserve Event shall be the difference between (i) the Batch Load Demand Resource's consumption at the end of the Non-Synchronized Reserve Event and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the end of the Non-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 Non-Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the

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

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

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

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

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

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

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the

"ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

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

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

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

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the

Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit hourly in an amount equal to {(LMPDMW - AG) x (URTLMP - UB)}

where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

AG equals the actual hourly integrated output of the unit;

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

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

where URTLMP - UB shall not be negative.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

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

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

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

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

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

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

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to Section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit hourly in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual hourly integrated output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

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

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

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generating unit's bus, (C) the generating unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generating resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generating unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsectonparagraph (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be

credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

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

3.2.5 Transmission Loss Charges.

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

3.2.6 Emergency Energy.

(a) *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.

(cb) 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.

(dc) The net costs or net revenues associated with sales or purchases of hourly energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each hour of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Buyer in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market Buyer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Buyer's internal accounting.

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

3.3 Market Sellers.

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

3.3.1 Spot Market Energy Charges.

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

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

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

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

3.3.2 Regulation.

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

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

3.3.3 Operating Reserves.

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

3.3.4 Emergency Energy.

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

3.3.5 Synchronized Reserve.

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

3.*3.5A Non-Synchronized Reserve.*

Each Market Seller that is also an Internal Market Buyer shall have an hourly Non-Synchronized Reserve objective and shall be credited or charged in connection therewith as specified in Section 3.2.3A.001(a). All other Market Sellers supplying Non-Synchronized Reserve at the direction of the Office of the Interconnection shall be credited for each increment of such Synchronized Reserve at the price specified in Section 3.2.3A.001(b), as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

3.3.6 Billing.

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

6A ~~***Scarcity Pricing***~~.[Reserved for Future Use]

6A.1 ~~Scarcity Conditions~~[Reserved For Future Use]

~~*6A.1.1 Commencement of Scarcity Conditions.*~~

~~*Scarcity conditions that trigger scarcity pricing will occur when the Office of the Interconnection's system operators perform any one of the following identifiable, specifically defined actions for a Scarcity Pricing Region:*~~

~~*a) Begin to dispatch online generators, which are partially designated as Maximum Emergency, into emergency output levels.*~~

~~*b) Begin to dispatch online generators, which are designated entirely as Maximum Emergency, above their designated minimum load points, if they are currently online and operating at their minimum load points because of restrictive operating parameters associated with the generators.*~~

~~*c) Begin to dispatch any offline generators that are designated entirely as Maximum Emergency and that have start times plus notification times less than or equal to 30 minutes.*~~

~~*d) Voltage reduction action as described in the PJM Manuals.*~~

~~*e) Emergency energy purchases pursuant to section 1.6.2(vi) of this Schedule.*~~

~~*f) Manual load dump action as described in the PJM Manuals.*~~

~~*Whenever the Office of the Interconnection's system operators take any of the above designated actions triggering scarcity pricing, they shall post on the PJM website the emergency message describing the action and include in the posting the Scarcity Pricing Region for which the action is being taken.*~~

~~*6A.1.2 Termination of Scarcity Conditions.*~~

~~*Scarcity pricing will be terminated in a Scarcity Pricing Region when demand and reserves can be fully satisfied with generation that is not designated Maximum Emergency. Under this condition, some generation that is designated Maximum Emergency may continue to operate due to timing limitations or operating limitations, but that generation is no longer needed under dispatch to satisfy system requirements, and scarcity pricing will no longer apply. Under no circumstances shall scarcity conditions be terminated if any of the following conditions remain in effect for the Scarcity Pricing Region:*~~

~~*a) Voltage reduction action as described in the PJM Manuals.*~~

~~*b) Emergency energy purchases from offers that do not have minimum purchase requirements of greater than 30 minutes duration attached to the offer.*~~

~~*c) Manual load dump action as described in the PJM Manuals.*~~

~~*The Office of the Interconnection shall post on the PJM website the time when scarcity conditions are terminated.*~~

~~*6A.1.3 Maximum Emergency Offer Limitations.*~~

~~*For purposes of defining scarcity conditions, the Office of the Interconnection shall consider units that have been classified as Maximum Emergency only if they fall in one of the following categories:*~~

~~*a) Environmental limits. If the unit has a hard cap on its run hours imposed by an environmental regulator that will temporarily significantly limit its availability.*~~

~~*b) Fuel limits. If physical events beyond the control of the unit owner result in the temporary interruption of fuel supply and there is limited on-site fuel storage. A fuel supplier's exercise of a contractual right to interrupt supply or delivery under an interruptible service agreement shall not qualify as an event beyond the control of the unit owner.*~~

~~*c) Temporary emergency conditions at the unit. If temporary emergency physical conditions at the unit significantly limit its availability.*~~

~~*d) Temporary megawatt additions. If a unit can provide additional megawatts on a temporary basis by oil topping, boiler over-pressure, or similar techniques and such megawatts are not ordinarily otherwise available.*~~

~~*The Office of the Interconnection shall post on its website the aggregate amount of generation megawatts that are classified as Maximum Emergency.*~~

6A.2 ~~***Scarcity Pricing Regions***~~.[Reserved for Future Use]

~~***6A.2.1 Established Scarcity Pricing Regions.***~~

~~*There shall be the following Scarcity Pricing Regions: (1) Entire Market Region consisting of all transmission zones in the PJM market; (2) Bedington-Black Oak Region consisting of all pricing nodes that have a 5% or greater positive power distribution factor ("dfax") relative to the Bedington-Black Oak constraint; (3) the Eastern MAAC Region consisting of all pricing nodes that have a 5% or greater dfax relative to the Eastern Reactive Transfer constraint, (4) Eastern Market Region consisting of all pricing nodes that have a 5% or greater positive dfax relative to the Bedington-Black Oak and the Central Reactive Transfer constraints; (5) the MAAC Region, consisting of all pricing nodes that have a 5% or greater positive dfax relative to the Western Reactive Transfer constraint; and (6) the AP South Region, consisting of all pricing nodes that have a 5% or greater positive dfax relative to the AP South Reactive Transfer constraint.*~~

~~***6A.2.2 Annual Review of Scarcity Pricing Regions.***~~

~~*On an annual basis, PJM will review the defined Scarcity Pricing Regions and file changes (additions or deletions) to them with the Commission, as required. Additional Scarcity Pricing Regions must meet the following criteria: (1) consist of at least two entire transmission zones; (2) consist of contiguous transmission zones and sub-zones; (3) transmission import or transfer must be limited by EHV (500 kV or greater) constraints; and (4) consist of pricing nodes that have a 5% or greater positive dfax relative to the constraints.*~~

~~***6A.2.3 Additional Temporary Scarcity Pricing Regions.***~~

~~*Additional temporary Scarcity Pricing Regions shall be designated by the Office of the Interconnection during the year when warranted by a non-transitory change in the topology of the transmission system. Additional temporary Scarcity Pricing Regions must meet the criteria set forth in section 6A.2.2. The Office of the Interconnection shall designate and post on the PJM website an additional temporary Scarcity Pricing Region within 72 hours of operational conditions warranting the additional temporary Scarcity Pricing Region. The temporary Scarcity Pricing Region shall become effective on the day following such posting, provided that the posting is before noon. If and when the topology is restored to its prior state or the change otherwise no longer warrants the designation of a temporary Scarcity Pricing Region, the Office of the Interconnection shall make a posting ending the additional designation. The termination of the temporary Scarcity Pricing Region shall become effective on the day following the posting, provided that the posting is before noon.*~~

6A.3 ~~***Scarcity Pricing.***~~[Reserved for Future Use]

~~*When scarcity conditions exist in a Scarcity Pricing Region, the region is considered incapable of meeting demand under normal economic dispatch conditions. Under such scarcity conditions, the Locational Marginal Prices of all nodes in a Scarcity Pricing Region will be determined based on the highest market-based offer price of all generating units operating under the Office of the Interconnection's direction to supply either energy or reserves on a real-time dispatch basis. No offer capping under section 6.4 of this Schedule may be initiated or continued in the Scarcity Pricing Region while scarcity pricing is in effect; provided, however, that generation in the Scarcity Pricing Region shall remain subject to the overall offer cap of $1000 per megawatt-hour. During the period that scarcity pricing is in effect, the Office of the Interconnection's system operators may direct generating units in the Scarcity Pricing Region to reduce from their maximum output for system or local transmission control. In such event, such reductions shall be treated as reductions for reliability under which the generation supplier shall be entitled to opportunity cost compensation equal to the megawatt-hour reduction times the difference between the Locational Marginal Price at the generator bus and the generation supplier's offer price consistent with section 3.2.3(f) of this Schedule. In addition, if a generator outside of a Scarcity Pricing Region is called upon to relieve the transmission constraint that caused the scarcity pricing condition in a Scarcity Pricing Region, then during the time that scarcity pricing is in effect in that Scarcity Pricing Region, that generation supplier shall be paid the higher of the generation-weighted Locational Marginal Price within the region determined as explained above or the price it otherwise would have been paid under this Schedule; however, that generation supplier's offer shall not be used to set Locational Marginal Prices in the Scarcity Pricing Region.*~~

PJM EMERGENCY LOAD RESPONSE PROGRAM

Emergency Load Response Program

The Emergency Load Response Program is designed to provide a method by which end-use customers may be compensated by PJM for reducing load during an emergency event. As used in the Emergency Load Response Program, the term "end-use customer" refers to an individual location or aggregation of locations that consume electricity as identified by a unique electric distribution company account number. There are two options for participation in the Emergency Load Response Program:

- Full Program Option

  Participants in the Full Program Option receive, pursuant to Attachment DD of the Tariff and as applicable, (i) an energy payment for load reductions during an emergency event, and (ii) a capacity payment for load reductions during an emergency event measured as set forth in the Reporting and Compliance provisions below.

- Energy Only Option

  Participants in the Energy Only Option receive only an energy payment for load reductions during an emergency event.

Participant Qualifications

Two primary types of distributed resources are candidates to participate in either of the two options provided by the Emergency Load Response Program:

On-Site Generators

These generators (including Behind The Meter Generation) can be either synchronized or non-synchronized to the grid. Capacity Resources are not eligible for compensation under this program. Injections into the grid by local generators also will not be eligible for compensation under this program.

Load Reductions

A participant that has the ability to reduce a measurable and verifiable portion of its load, as metered on an EDC account basis.

PJM membership is required to participate in either of the two options provided by the Emergency Load Response Program. Members or Special Members may participate in the Emergency Load Response Program by complying with all of the requirements of the applicable Relevant Electric Retail Regulatory Authority and all other applicable federal, state and local regulatory entities together with the Emergency Load Response provisions herein, including, but

not limited to, the Registration section. Special membership provisions have been established for program participants in the Energy Only Option, as described below. The special membership provisions shall not apply to program participants in the Full Program Option. Any existing PJM Member may act as a third party for non-members, in which case the third party will be referred to as the Curtailment Service Provider (CSP). All payments are made to the PJM Member. Participants must become signatories to the PJM Operating Agreement, as described in the ***PJM Manual for Administrative Services for the Operating Agreement of the PJM Interconnection, L.L.C***. However, for special members the $5,000 annual membership fee, the $1,500 application fee, and liability for Member defaults are waived, along with the following other modifications:

Special Members are limited to be PJM market sellers;
Voting privileges and sector designation are waived;
Thirty day notice for waiting period is waived;
Requirement for 24/7 control center coverage is waived;
No PJM-supported user group capability is permitted.

To participate in either of the two options provided by the Emergency Load Response Program, the distributed resource must:

Be capable of reducing at least 100 kW of load
Be capable of receiving PJM notification to participate during emergency conditions.

Metering Requirements

The Curtailment Service Provider is responsible to ensure that the Emergency Load Response Program Participants have metering equipment that provides integrated hourly kWh values on an electric distribution company account basis. The metering equipment shall either meet the electric distribution company requirements for accuracy or have a maximum error of two percent over the full range of the metering equipment (including Potential Transformers and Current Transformers) and the metering equipment and associated data shall meet the requirements set forth herein and in the PJM Manuals. The Emergency Load Response Participant must meter reductions in demand by using either of the following two methods:

a) Using metering equipment that is capable of recording integrated hourly values for generation running to serve local load (net of that used by the generator); or

b) Using metering equipment that provides actual load change by measuring actual load before and after the reduction request, such that there is a valid integrated hourly value for the hour prior to the event and each hour during the event. This value cannot be estimated nor can it be averaged over some historical period. This load will be metered on an electric distribution company account basis.

Metered load reductions will be adjusted up to consider transmission and distribution losses as submitted by the Curtailment Service Provider and verified by PJM with the electric distribution company.

The installed metering equipment must be one of the following:

a) Metering equipment used for retail electric service;

b) Customer-owned metering equipment or metering equipment acquired by the Curtailment Service Provider, approved by PJM, that is read electronically by PJM, in accordance with the requirements herein and in the PJM Manuals; or

c) Customer-owned metering equipment or metering equipment acquired by the Curtailment Service Provider, approved by PJM, that is read by the customer (or the Curtailment Service Provider), and such readings are then forwarded to PJM, in accordance with the requirements set forth herein and in the PJM Manuals.

Nothing herein changes the existence of one recognized meter by the state commissions as the official billing meter for recording consumption.

Registration

1. Participants must complete the PJM Emergency Load Response Program Registration Form ("Emergency Registration Form") that is posted on the PJM website (www.pjm.com)for each end-use customer, or aggregation of end-use customers, pursuant to the requirements set forth in the PJM Manuals. Because of the required electric distribution company and Load Serving Entity ten business day review period, as described herein, Participants should submit completed PJM Emergency Load Response Program Registration Forms to the Office of the Interconnection no later than one day before the tenth business day preceding the relevant Delivery Year. All registrations that have not been approved on or before May 31st preceding the relevant Delivery Year shall be rejected by the Office of the Interconnection. To the extent that a completed PJM Emergency Load Response Program Registration Form is submitted to the Office of the Interconnection prior to one day before the tenth business day preceding the relevant Delivery Year and such registration is rejected by the electric distribution company or Load Serving Entity or the Office of the Interconnection because of incorrect data on the PJM Emergency Load Response Program Registration Form, such registration may be resubmitted by the participant before May 31st preceding the relevant Delivery Year, but such registration will be rejected by the Office of the Interconnection unless the electric distribution company or Load Serving Entity has verified the registration on or before May 31st preceding the relevant Delivery Year. Incomplete PJM Emergency Load Response Program Registration Forms will be rejected by the Office of the Interconnection; participants may not resubmit registrations that were rejected for being incomplete unless participants are able to do so no later than one day before the tenth business day preceding the relevant Delivery Year. The following general steps will be followed:

2. For end-use customers of an electric distribution company that distributed more than 4 million MWh in the previous fiscal year:

a. The participant completes the Emergency Registration Form located on the PJM website. PJM reviews the application and ensures that the qualifications are met, including

verifying that the appropriate metering exists. After confirming that an entity has met all of the qualifications to be an Emergency Load Response Participant, PJM shall notify the appropriate Load Serving Entity and electric distribution company of an Emergency Load Response Participant's registration and request verification as to whether the load that may be reduced is under other contractual obligations or subject to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Emergency Load Response Program pursuant to the process described below. The electric distribution company and Load Serving Entity have ten business days to respond. Other such contractual obligations may not preclude participation in the program, but may require special consideration by PJM such that appropriate settlements are made within the confines of such existing contracts. An electric distribution company or Load Serving Entity which seeks to assert that the laws or regulations of the Relevant Electric Retail Regulatory Authority prohibit or condition (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) an end-use customer's participation in PJM's Emergency Load Response Program shall provide to PJM, within the referenced ten business day review period, either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority prohibiting or conditioning the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation.

i. If evidence provided by an electric distribution company or Load Serving Entity to the Office of the Interconnection indicates that a Relevant Electric Retail Regulatory Authority law or regulation prohibits or conditions (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation and is received by the Office of the Interconnection on or after the Interruptible Load for Reliability registration deadline established by the Office of the Interconnection for the next applicable Delivery Year, then the existing Emergency Load Response Participant's registration for Interruptible Load for Reliability (as defined in the Reliability Assurance Agreement) will remain in effect for the applicable Delivery Year. If evidence provided by an electric distribution company or Load Serving Entity to the Office of the Interconnection indicates that a Relevant Electric Retail Regulatory Authority law or regulation prohibits or conditions (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation and is received by the Office of the Interconnection before the Interruptible Load for Reliability registration deadline established by the Office of the Interconnection for the applicable Delivery Year, then the existing Emergency Load Response participant's registration for Interruptible Load for Reliability (as defined in the Reliability Assurance Agreement) participation shall be deemed to be terminated for the applicable Delivery Year.

ii. If evidence provided by an electric distribution company or Load Serving Entity to the Office of the Interconnection indicates that a Relevant Electric Retail Regulatory Authority law or regulation prohibits or conditions (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation and is received by the Office of the Interconnection on or after May 31st preceding the applicable Delivery Year, then the existing end-use customer's registration for Demand Resource (as defined in the Reliability Assurance Agreement) will remain in effect for the applicable Delivery Year. If evidence provided by an electric distribution company or Load Serving Entity to the Office of the Interconnection indicates that a Relevant Electric Retail Regulatory Authority law or regulation prohibits or conditions (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation and is received by the Office of the Interconnection before May 31st preceding the applicable Delivery Year and the Curtailment Service Provider does not provide supporting documentation to the Office of the Interconnection on or before May 31st preceding the applicable Delivery Year demonstrating that the Curtailment Service Provider had an executed contract with the end-use customer for Demand Resource participation before the date the Demand Resource cleared the applicable Reliability Pricing Model Auction, and that the date that the Demand Resource cleared the applicable Reliability Pricing Model Auction was prior to the effective date of the Relevant Electric Retail Regulatory Authority law or regulation prohibiting or conditioning the end-use customer's participation, then, unless the below exception applies, the existing end-use customer's registration for Demand Resource participation shall be deemed to be terminated for the applicable Delivery Year, and the Curtailment Service Provider will be subject to the Reliability Pricing Model provisions, as specified in Attachment DD of the PJM Tariff.

(1) Except that, pursuant to all other PJM Tariff and PJM Manual provisions, PJM will allow participation of all end-use customers registered by Curtailment Service Providers to fulfill Curtailment Service Providers' Demand Resource obligations that were cleared in the Reliability Pricing Model Auctions prior to August 28, 2009.

b. In the absence of a response from the electric distribution company or Load Serving Entity within the referenced ten business day review period, the Office of the Interconnection shall assume that the load to be reduced is not subject to other contractual obligations or to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Emergency Load Response Program, and the Office of the Interconnection shall accept the registration, provided it meets all other Emergency Load Response Program requirements.

c. For those registrations terminated pursuant to this section, all Emergency Load Response Participant activity incurred prior to the termination date of the registration shall be settled by PJM in accordance with the terms and conditions contained in the PJM Tariff, PJM Operating Agreement and PJM Manuals.

3. For end-use customers of an electric distribution company that distributed 4 million MWh or less in the previous fiscal year:

a. The Participant completes the Emergency Registration Form located on the PJM website. PJM reviews the application and ensures that the qualifications are met, including verifying that the appropriate metering exists. After confirming that an entity has met all of the qualifications to be an Emergency Load Response Participant, PJM shall notify the appropriate Load Serving Entity and electric distribution company of an Emergency Load Response Participant's registration and request verification as to whether the load that may be reduced is under other contractual obligations and is permitted to participate by the Relevant Electric Retail Regulatory Authority pursuant to the process described below. The electric distribution company and Load Serving Entity have ten business days to respond. Other such contractual obligations may not preclude participation in the program, but may require special consideration by PJM such that appropriate settlements are made within the confines of such existing contracts. If the electric distribution company or Load Serving Entity verifies that the load that may be reduced is permitted or conditionally permitted (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) to participate in the Emergency Load Response Program, then the electric distribution company or Load Serving Entity must provide to the Office of the Interconnection within the referenced ten business day review period either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation.

i. If the electric distribution company or Load Serving Entity denies the Interruptible Load for Reliability (as defined in the Reliability Assurance Agreement) registration before the Interruptible Load for Reliability registration deadline as established by the Office of the Interconnection for the applicable Delivery Year because the electric distribution company or Load Serving Entity asserts that the Relevant Electric Retail Regulatory Authority has not granted permission or conditional permission for the end-use customer's participation or the electric distribution company or Load Serving Entity asserts that the end-use customer has not satisfied conditional permission requirements, then the existing Emergency Load Response Participant's registration for Interruptible Load for Reliability participation shall be deemed to be terminated for the applicable Delivery Year. If it is able to do so in compliance with all Emergency Load Response Program requirements, including the registration requirements,

the participant may submit a new registration to the Office of the Interconnection for consideration if a prior registration has been rejected pursuant to the terms of the Emergency Load Response Program provisions.

ii. If the electric distribution company or Load Serving Entity denies the end-use customer's Demand Resource (as defined in the Reliability Assurance Agreement) registration on or before May 31st preceding the applicable Delivery Year and the Curtailment Service Provider does not provide the above referenced Relevant Electric Retail Regulatory Authority evidence to the Office of the Interconnection on or before May 31st preceding the applicable Delivery Year demonstrating that the Curtailment Service Provider had Relevant Electric Retail Regulatory Authority permission or conditional permission (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) for the end-use customer's participation and an executed contract with the end-use customer Demand Resource before the date the Demand Resource cleared the applicable Reliability Pricing Model Auction then, unless the below exception applies, the existing end-use customer's registration for Demand Resource registration for Demand Resource participation shall be deemed to be terminated for the applicable Delivery Year and the Curtailment Service Provider will be subject to the Reliability Pricing Model provisions, as specified in Attachment DD of the PJM Tariff.

(1) Except that, pursuant to all other PJM Tariff and PJM Manual provisions, PJM will allow participation of all end-use customers registered by Curtailment Service Providers to fulfill Curtailment Service Providers' Demand Resource obligations that were cleared in the Reliability Pricing Model Auctions prior to August 28, 2009.

b. In the absence of a response from the electric distribution company or Load Serving Entity within the referenced ten business day review period, the Office of the Interconnection shall reject the registration. If it is able to do so in compliance with all of the Emergency Load Response Program requirements, including the registration section, the Emergency Load Response Participant may submit a new registration to the Office of the Interconnection for consideration if a prior registration has been rejected pursuant to the terms of the Emergency Load Response Program provisions.

c. For those registrations terminated pursuant to this section, all Emergency Load Response participant activity incurred prior to the termination date of the registration shall be settled by PJMSettlement in accordance with the terms and conditions contained in the PJM Tariff, PJM Operating Agreement and PJM Manuals.

4. PJM informs the requesting participant of acceptance into the program and notifies the appropriate Load Serving Entity and electric distribution company of the requesting participant's acceptance into the program, or notifies the requesting participant and appropriate Load Serving

Entity and electric distribution company of PJM's rejection of the requesting participant's registration.

5. Any end-use customer intending to run distributed generating units in support of local load for the purpose of participating in this program must represent in writing to PJM that it holds all applicable environmental and use permits for running those generators. Continuing participation in this program will be deemed as a continuing representation by the owner that each time its distributed generating unit is run in accordance with this program, it is being run in compliance with all applicable permits, including any emissions, run-time limit or other constraint on plant operations that may be imposed by such permits.

Emergency Load Response Registrations in Effect as of August 28, 2009

All existing Emergency Load Response Participants' registrations submitted to PJM prior to August 28, 2009 (the effective date of *Wholesale Competition in Regions with Organized Electric Markets*, Order 719-A, 128 FERC ¶ 61,059 (2009) ("Order 719-A")) for Load Management participation in the 2009/2010 Delivery Year will remain effective for that Delivery Year.

Emergency Operations

PJM will initiate the request for load reduction following the declaration of Maximum Emergency Generation and prior to the implementation of Load Management Steps 1 and 2. (Implementation of the Emergency Load Response Program can be used for regional emergencies.) It is implemented whenever generation is needed that is greater than the highest economic incremental cost. PJM posts the request for load reduction on the PJM website, on the Emergency Conditions page, and on eData, and issues a burst email to the Emergency Load Response majordomo. A separate All-Call message is also issued.

Following PJM's request to reduce load, (i) participants in the Energy Only Option voluntarily may reduce load; and (ii) participants in the Full Program Option are required to reduce load unless they already have reduced load pursuant to the Economic Load Response Program. PJM will dispatch the resources of all Emergency Load Response Program participants (not already dispatched under the Economic Load Response Program) based on the Minimum Dispatch Prices specified in the participants' Emergency Registration Forms.

The Minimum Dispatch Price *and all offers* of ~~*a*~~ Full Program Option ~~*participant*~~ *resources and Energy Only Option resources in the Emergency Load Response Program are eligible to* ~~*that reduces load may*~~ set the real time Locational ~~m~~Marginal Prices ("LMP") *when the Office of the Interconnection has implemented Emergency procedures and* ~~*provided that the*~~ *such resources* ~~*participant's load reductions*~~ *are* ~~*needed*~~ *required* to ~~*meet*~~ *reduce* demand in the PJM Region, *so long as sufficient data is available to accurately model the resources.* ~~*The Minimum Dispatch Price of an Energy Only Option participant that reduces load may set the real time LMP provided that such participant's load reductions are needed to meet demand in the PJM Regions and the*~~ Energy Only Option ~~*participant's*~~ resources *must also* satisf~~*ies*~~ PJM's telemetry requirements.

Participants in the Emergency Load Response Program must provide real-time operational data regarding the availability and status of their resources to PJM, as described in detail in the PJM Manuals. Operational procedures are described in detail in the ***PJM Manual for Emergency Operations.***

Verification

PJM requires that the load reduction meter data be submitted to PJM within 60 days of the event. If the data are not received within 60 days, no payment for participation is provided. Meter data must be provided for all hours during the day of the Load Management event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. These data files are to be communicated to PJM either via the Load Response Program web site or email. Files that are emailed must be in the PJM-approved file format. Meter data will be forwarded to the EDC and LSE upon receipt, and these parties will then have ten (10) business days to provide feedback to PJM.

Market Settlements

Payment for reducing load is based on the actual kWh relief provided plus the adjustment for losses, subject to the Reporting and Compliance provisions below. The minimum duration of a load reduction request is two hours. The magnitude of capacity relief provided by Full Program Option participants shall be the amount determined in accordance with the Reporting and Compliance provisions below. The magnitude of relief provided by Energy Only Option participants, and the magnitude of energy relief provided by Full Program Option participants, may be less than, equal to, or greater than the kW amount declared on the Emergency Registration Form. Compensation will be provided for reductions in energy consumption during emergency events by Full Program Option participants and Energy Only Option participants regardless of whether the participant's load during the event exceeds its peak load contribution for the applicable Delivery Year.
PJMSettlement pays the applicable LMP to the PJM Member that nominates the load. Payment will be equal to the measured reduction (either measured output of backup generation or the difference between the measured load the hour before the reduction and each hour during the reduction) adjusted for losses times the applicable LMP. If, however, the sum of the hourly energy payments to a participant dispatched by PJM for actual, achieved reductions is not greater than or equal to the offer value (i.e. Minimum Dispatch Price, minimum down time and shut down costs) then the participant will be made whole up to the offer value for its actual, achieved reductions.

Full Program Option participants that fail to provide a load reduction (as measured as set forth in the Reporting and Compliance provisions below) when dispatched by PJM shall be assessed penalties and/or charges as specified in Attachment DD of the PJM Tariff and the Reliability Assurance Agreement, as applicable.

During emergency conditions, costs for emergency purchases in excess of LMP are allocated among PJM Market Buyers in proportion to their increase in net purchases minus real-time

dispatch reduction megawatts from the PJM energy market during the hour in the real time market compared to the day-ahead market. Consistent with this pricing methodology, all charges under this program are allocated to purchasers of energy, in proportion to their increase in net purchases minus real-time dispatch reduction megawatts from the PJM energy market during the hour from day-ahead to real time.

Program charges and credits will appear on the PJM Members monthly bill, as described in the ***PJM Manual for Operating Agreement Accounting and the PJM Manual for Billing.***

Reporting and Compliance

Actual load reductions of Energy Only Option emergency resources will be added back for the purpose of peak load calculations for capacity for the following Delivery Year.

Actual Emergency Load Response and Economic Load Response load reductions for Load Management resources registered as Emergency Load Response Full Program Option or Capacity Only resources which occur from June 1 through September 30, will be added back for the purpose of calculating peak load for capacity for the following Delivery Year, as set forth in the PJM Manuals and consistent with the load response recognized for capacity compliance as set forth in the Reporting and Compliance provisions below. Capacity Only resources are Full Program Option resources that do not receive an energy payment for load reductions during an emergency event.

Actual load reductions of Load Management resources registered as Emergency Load Response Full Program Option or Capacity Only resources used to determine Load Management event and test capacity compliance for Firm Service Level and Guaranteed Load Drop end-use customers shall be equal to the load reduction provided to the electric distribution company as follows and in accordance with the PJM Manuals:

i) For Guaranteed Load Drop end-use customers, the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the metered load ("Load") and then multiplied by the loss factor ("LF") or (b) the current Delivery Year peak load contribution ("PLC") minus the metered load multiplied by the loss factor ("LF"). A load reduction will only be recognized for capacity compliance if the metered load multiplied by the loss factor is less than the current Delivery Year peak load contribution. The calculation is represented by:

   Minimum of {(comparison load – Load) * LF, PLC – (Load * LF)}

   Methodologies for establishing comparison load for Guaranteed Load Drop end-use customers include the following:

   Comparable Day: A single weekday that is comparable to the event or test day and accurately represents what the customer's load would have been absent the event or test.

Same Day: The customer‘s average hourly integrated consumption during specified hours on the same day as an emergency or test event.

Customer Baseline: The estimated baseline used to calculate load reductions for end-use customers registered with PJM as economic demand resources.

Regression Analysis: An estimate, based on a regression analysis of the customer’s actual loads versus weather, of what the customer’s load would have been, had PJM not declared an emergency or test.

Generation: The hourly integrated output from a generator used to reduce the customer’s consumption of energy from PJM during an emergency or test event if the generator would not have otherwise been used on the event or test day.

Each of these methodologies is described in greater detail in Manual M-19, ***PJM Manual for Load Forecasting and Analysis***, at Attachment A: Load Drop Estimate Guidelines.

ii) For Firm Service Level end-use customers the current Delivery Year peak load contribution (“PLC”) minus the metered load (“Load”) multiplied by the loss factor (“LF”). The calculation is represented by:

PLC – (Load * LF)

The capacity compliance of Load Management resources that are registered as Emergency Load Response Full Program Option, as determined in accordance with these Reporting and Compliance provisions, shall not affect energy payments to such resources for load reductions during an emergency event, as provided in the Market Settlements provisions above and Attachment DD of the Tariff.

PJM will submit any required reports to FERC on behalf of the Load Response Program participants. PJM will also post this document, as well as any other program-related documentation on the PJM website.

PJM will post on its website a report of demand response activity, and will provide a summary thereof to the PJM Markets and Reliability Committee on an annual basis.

As PJM receives evidence from the electric distribution companies or Load Serving Entities pursuant to section 1.3 of PJM Emergency Load Response Program, PJM will post on its website a list of those Relevant Electric Retail Regulatory Authorities that the electric distribution companies or Load Serving Entities assert prohibit or condition retail participation in PJM’s Emergency Load Response Program together with a corresponding reference to the Relevant Electric Retail Regulatory Authority evidence that is provided to PJM by the electric distribution companies or Load Serving Entities.

Non-hourly metered Customer Pilot

Non-hourly metered customers may participate in the Emergency Load Response Program on a pilot basis under the following circumstances. The customer or its Curtailment Service Provider or Load Serving Entity must propose an alternate method for measuring hourly demand reductions. The Office of the Interconnection shall approve alternate measurement mechanisms on a case-by-case basis for a time period specified by the Office of the Interconnection ("Pilot Period"). In the event an alternative measurement mechanism is approved, the Office of the Interconnection shall notify the affected Load Serving Entity(ies) that a proposed alternate measurement mechanism has been approved for a Pilot Period.

Demand reductions by non-hourly metered customers using alternate measurement mechanisms on a pilot basis shall be limited to a combined total of 500 MW of reductions in both the Emergency Load Response Program and the PJM Interchange Energy Market. With the sole exception of the requirement for hourly metering, non-hourly metered customers shall be subject to the rules and procedures for participation in the Emergency Load Response Program. Following completion of a Pilot Period, the alternate method shall be evaluated by the Office of the Interconnection to determine whether such alternate method should be included in the PJM Manuals as an accepted measurement mechanism for demand reductions in the Emergency Load Response Program.

Emergency Load Response Participant Aggregation.

The purpose for aggregation is to allow the participation of End-Use Customers in the Emergency Load Response Program that can provide less than 100 kW of demand response on an individual basis. Emergency Load Response Participant aggregations shall be subject to the following requirements:

i. All End-Use Customers in an aggregation shall be specifically identified;

ii. All End-Use Customers in an aggregation shall be served by the same electric distribution company or Load Serving Entity where the electric distribution company is the Load Serving Entity for all End-Use Customers in the aggregation;

iii. All End-Use Customers in an aggregation that settle at Transmission Zone, existing load aggregate, or node prices shall be located in the same Transmission Zone, existing load aggregate or at the same node, respectively;

iv. Energy settlement will be based on each individual customer's load reductions pursuant to section 3.3A of Schedule 1 of this Agreement, the PJM Reliability Assurance Agreement Among Load Serving Entities in the PJM Region and the PJM Manuals. Capacity compliance will be based on each individual customers' load reductions and then aggregated pursuant to section 3.3A of Schedule 1 of this Agreement, the PJM Reliability Assurance Agreement Among Load Serving Entities in the PJM Region and the PJM Manuals; and

v. Each End-Use Customer site must meet the requirements for market participation by a Demand Resource.

vi. Certain aggregations of End-Use Customers registered as Full Program Option or Capacity Only Option are subject to the "Demand Response Transition Provision for RPM Delivery Years 2012/2013, 2013/2014, and 2014/2015" in Section 5.14A of Attachment DD of the Tariff.

5.10 Auction Clearing Requirements

The Office of the Interconnection shall clear each Base Residual Auction and Incremental Auction for a Delivery Year in accordance with the following:

a) Variable Resource Requirement Curve

The Office of the Interconnection shall determine Variable Resource Requirement Curves for the PJM Region and for such Locational Deliverability Areas as determined appropriate in accordance with subsection (a)(iii) for such Delivery Year to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards. It is recognized that the variable resource requirement reflected in the Variable Resource Requirement Curve can result in an optimized auction clearing in which the level of Capacity Resources committed for a Delivery Year exceeds the PJM Region Reliability Requirement (less the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012, or less the Short-Term Resource Procurement Target for Delivery Years thereafter) or Locational Deliverability Area Reliability Requirement (less the Forecast Zonal ILR Obligation for Delivery Years through May 31, 2012, or less the Short-Term Resource Procurement Target for Delivery Years thereafter for the Zones associated with such LDA) for such Delivery Year. For any auction, the Updated Forecast Peak Load, and Short-Term Resource Procurement Target applicable to such auction, shall be used, and Price Responsive Demand from any applicable approved PRD Plan, including any associated PRD Reservation Prices, shall be reflected in the derivation of the Variable Resource Requirement Curves, in accordance with the methodology specified in the PJM Manuals.

i) Methodology to Establish the Variable Resource Requirement Curve

Prior to the Base Residual Auction, in accordance with the schedule in the PJM Manuals, the Office of the Interconnection shall establish the Variable Resource Requirement Curve for the PJM Region as follows:

- Each Variable Resource Requirement Curve shall be plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis;
- The Variable Resource Requirement Curve for the PJM Region shall be plotted by first combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), (iii) a straight line connecting points (2) and (3), and (iv) a vertical line from point (3) to the x-axis, where:
    - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin ("IRM")% minus

3%) divided by (100% plus IRM%)] minus the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter;

- For point (2), price equals: (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset) divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 1%) divided by (100% plus IRM%)] minus the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter; and

- For point (3), price equals [0.2 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 5%) divided by (100% plus IRM%)] minus the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter;

ii) For any Delivery Year, the Office of the Interconnection shall establish a separate Variable Resource Requirement Curve for each LDA for which:

A. the Capacity Emergency Transfer Limit is less than 1.15 times the Capacity Emergency Transfer Objective, as determined by the Office of the Interconnection in accordance with NERC and Applicable Regional Reliability Council guidelines; or

B. such LDA had a Locational Price Adder in any one or more of the three immediately preceding Base Residual Auctions; or

C. such LDA is determined in a preliminary analysis by the Office of the Interconnection to be likely to have a Locational Price Adder, based on historic offer price levels; provided however that for the Base Residual Auction conducted for the Delivery Year commencing on June 1, 2012, the EMAAC, SWMAAC and MAAC LDAs shall employ separate Variable Resource Requirement Curves regardless of the outcome of the above three tests; and provided further that the Office of the Interconnection may establish a separate Variable Resource Requirement Curve for an LDA not otherwise qualifying under the above three tests if it finds that such is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards, in which case the Office of the Interconnection shall post such finding, such LDA, and such

Variable Resource Requirement Curve on its internet site no later than the March 31 last preceding the Base Residual Auction for such Delivery Year. The same process as set forth in subsection (a)(i) shall be used to establish the Variable Resource Requirement Curve for any such LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement and the LDA Short-Term Resource Procurement Target shall be substituted for the PJM Region Short-Term Resource Procurement Target. For purposes of calculating the Capacity Emergency Transfer Limit under this section, all generation resources located in the PJM Region that are, or that qualify to become, Capacity Resources, shall be modeled at their full capacity rating, regardless of the amount of capacity cleared from such resource for the immediately preceding Delivery Year.

iii) Procedure for ongoing review of Variable Resource Requirement Curve shape.

Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall perform a review of the shape of the Variable Resource Requirement Curve, as established by the requirements of the foregoing subsection. Such analysis shall be based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis. Based on the results of such review, PJM shall prepare a recommendation to either modify or retain the existing Variable Resource Requirement Curve shape. The Office of the Interconnection shall post the recommendation and shall review the recommendation through the stakeholder process to solicit stakeholder input. If a modification of the Variable Resource Requirement Curve shape is recommended, the following process shall be followed:

A) If the Office of the Interconnection determines that the Variable Resource Requirement Curve shape should be modified, Staff of the Office of the Interconnection shall propose a new Variable Resource Requirement Curve shape on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

B) The PJM Members shall review the proposed modification to the Variable Resource Requirement Curve shape.

C) The PJM Members shall either vote to endorse the proposed modification, to propose alternate modifications or to recommend no modification by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) The PJM Board of Managers shall consider a proposed modification to the Variable Resource Requirement Curve shape, and the Office of the Interconnection shall file any approved modified Variable Resource Requirement Curve shape with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

iv) Cost of New Entry

A) For the Delivery Year commencing on June 1, 2012, and continuing thereafter unless and until changed pursuant to subsection (B) below, the Cost of New Entry for the PJM Region shall be $112,868 per MW-year. The Cost of New Entry for each LDA shall be determined based upon the Transmission Owner zones that comprise such LDA, as provided in the table below. If an LDA combines transmission zones with differing Cost of New Entry values, the lowest such value shall be used.

Geographic Location Within the PJM Region Encompassing These Zones	**Cost of New Entry in $/MW-Year**
PS, JCP&L, AE, PECO, DPL, RECO ("CONE Area 1")	134,000
BGE, PEPCO ("CONE Area 2")	123,700
AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK ("CONE Area 3")	123,500
PPL, MetEd, Penelec ("CONE Area 4")	130,100
Dominion ("CONE Area 5")	111,000

B) Beginning with the 2013-2014 Delivery Year, the CONE shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable H-W Index, in accordance with the following:

(1) The Applicable H-W Index for any Delivery Year shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in the Total Other Production Plant Index shown in the Handy-Whitman Index of Public Utility Construction Costs for the North Atlantic Region for purposes of CONE Areas 1, 2, and 4, for the North Central Region for purposes of CONE Area 3, and for the South Atlantic Region for purposes of CONE Area 5.

(2) The CONE in a CONE Area shall be adjusted prior to the Base Residual Auction for each Delivery Year by applying the Applicable H-W Index for such CONE Area to the Benchmark CONE for such CONE Area.

(3) The Benchmark CONE for a CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year.

(4) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vii)(C) or any filing to establish new or revised CONE Areas.

v) Net Energy and Ancillary Services Revenue Offset

A) The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (A) the annual average of the revenues that would have been received by the Reference Resource from the PJM energy markets during a period of three consecutive calendar years preceding the time of the determination, based on (1) the heat rate and other characteristics of such Reference Resource; (2) fuel prices reported during such period at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals, assumed variable operation and maintenance expenses for such resource of $6.47 per MWh, and actual PJM hourly average Locational Marginal Prices recorded in the PJM Region during such period; and (3) an assumption that the Reference Resource would be dispatched for both the Day-Ahead and Real-Time Energy Markets on a Peak-Hour Dispatch basis; plus (B) ancillary service revenues of $2,199 per MW-year.

B) The Office of the Interconnection also shall determine a Net Energy and Ancillary Service Revenue Offset each year for each sub-region of the PJM Region for which the Cost of New Entry is determined as identified above, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the average hourly LMPs for the Zone in which the Reference Resource was assumed to be installed for purposes of the CONE estimate (as specified in the PJM Manuals) shall be used in place of the PJM Region average hourly LMPs; (2) if such sub-region was not integrated into the PJM Region for the entire applicable period, then the offset shall be calculated using only those whole calendar years during which the sub-region was integrated; and (3) a posted fuel pricing point in such sub-region, if available, and (if such pricing point is not available) a fuel

transmission adder appropriate to each assumed Cost of New Entry location from an appropriate PJM Region pricing point shall be used for each such sub-region.

~~*vi) Adjustment to Net Energy and Ancillary Services Revenue Offset*~~

~~*Beginning with the Base Residual Auction scheduled for May 2010, the Net Energy and Ancillary Services Revenue Offset for a CONE Area shall be adjusted following any Delivery Year during which Scarcity Pricing was effective in such CONE Area pursuant to the Scarcity Pricing provisions of section 6A of Schedule 1 to the PJM Operating Agreement. Following each Delivery Year, the Scarcity Pricing revenues the Reference Resource in each CONE Area would have received during such Delivery Year shall be calculated based on the assumed heat rate and other characteristics of the Reference Resource, assumed Peak-Hour Dispatch, and the actual locational marginal prices and actual fuel prices during the Delivery Year for the applicable location, which shall be the transmission zone in which such resource was assumed to be installed for purposes of the estimate of CONE applicable to such CONE Area. The Scarcity Pricing revenues so determined shall be subtracted from the Net CONE otherwise calculated for such CONE Area for use in the Base Residual Auction next occurring after the Delivery Year in which Scarcity Pricing was effective in such CONE Area.*~~

vii) Process for Establishing Parameters of Variable Resource Requirement Curve

A) The parameters of the Variable Resource Requirement Curve will be established prior to the conduct of the Base Residual Auction for a Delivery Year and will be used for such Base Residual Auction.

B) The Office of the Interconnection shall determine the PJM Region Reliability Requirement and the Locational Deliverability Area Reliability Requirement for each Locational Deliverability Area for which a Variable Resource Requirement Curve has been established for such Base Residual Auction on or before February 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values will be applied, in accordance with the Reliability Assurance Agreement.

C) Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall review the calculation of the Cost of New Entry for each CONE Area.

1) If the Office of the Interconnection determines that the Cost of New Entry values should be modified, the Staff of the Office of the Interconnection shall propose new Cost of New Entry values on or before September 1, prior to the

conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

2) The PJM Members shall review the proposed values.

3) The PJM Members shall either vote to endorse the proposed values or propose alternate values by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

4) The PJM Board of Managers shall consider Cost of New Entry values, and the Office of the Interconnection shall file any approved modified Cost of New Entry values with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall review the methodology set forth in this Attachment for determining the Net Energy and Ancillary Services Revenue Offset for the PJM Region and for each Zone.

1) If the Office of the Interconnection determines that the Net Energy and Ancillary Services Revenue Offset methodology should be modified, Staff of the Office of the Interconnection shall propose a new Net Energy and Ancillary Services Revenue Offset methodology on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

2) The PJM Members shall review the proposed methodology.

3) The PJM Members shall either vote to endorse the proposed methodology or propose an alternate methodology by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

4) The PJM Board of Managers shall consider the Net Revenue Offset methodology, and the Office of the Interconnection shall file any approved modified Net Energy and Ancillary Services Revenue Offset values with

the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

b) Locational Requirements

The Office of Interconnection shall establish locational requirements prior to the Base Residual Auction to quantify the amount of Unforced Capacity that must be committed in each Locational Deliverability Area, in accordance with the PJM Reliability Assurance Agreement.

c) Minimum Annual Resource Requirements

Prior to the Base Residual Auction and each Incremental Auction for each Delivery Year, beginning with the Delivery Year that starts on June 1, 2014, the Office of the Interconnection shall establish the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year.

d) Preliminary PJM Region Peak Load Forecast for the Delivery Year

The Office of the Interconnection shall establish the Preliminary PJM Region Load Forecast for the Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the Base Residual Auction for such Delivery Year.

e) Updated PJM Region Peak Load Forecasts for Incremental Auctions

The Office of the Interconnection shall establish the updated PJM Region Peak Load Forecast for a Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the First, Second, and Third Incremental Auction for such Delivery Year.

Sections of the
PJM Operating Agreement

Marked/Redline Version

1.38.01 Regional RTEP Project.

"Regional RTEP Project" shall mean a transmission expansion or enhancement rated at 230 kV or above which is required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.

1.38.01A Relevant Electric Retail Regulatory Authority:

An entity that has jurisdiction over and establishes prices and policies for competition for providers of retail electric service to end-customers, such as the city council for a municipal utility, the governing board of a cooperative utility, the state public utility commission or any other such entity.

1.38A Regulation Zone.

"Regulation Zone" shall mean any of those one or more geographic areas, each consisting of a combination of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, regulation service.

1.39 Related Parties.

"Related Parties" shall mean, solely for purposes of the governance provisions of this Agreement: (i) any generation and transmission cooperative and one of its distribution cooperative members; and (ii) any joint municipal agency and one of its members. For purposes of this Agreement, representatives of state or federal government agencies shall not be deemed Related Parties with respect to each other, and a public body's regulatory authority, if any, over a Member shall not be deemed to make it a Related Party with respect to that Member.

1.40 Reliability Assurance Agreement.

"Reliability Assurance Agreement" shall mean that certain Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region, on file with FERC as PJM Interconnection, L.L.C. Rate Schedule FERC. No .42, establishing obligations, standards and procedures for maintaining the reliable operation of the PJM Region.

1.40A ~~[Reserved]~~*Reserve Zone*.

"Reserve Zone" shall mean any of those geographic areas consisting of a combination of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, reserve service.

1.40B [Reserved].

1.40C SERC.

"SERC" or "Southeastern Electric Reliability Council" shall mean the reliability council under section 202 of the Federal Power Act established pursuant to the SERC Agreement dated January 14, 1970, or any successor thereto.

1.41 Sector Votes.

"Sector Votes" shall mean the affirmative and negative votes of each sector of a Senior Standing Committee, as specified in Section 8.4.

1.41A Senior Standing Committees.

"Senior Standing Committees" shall mean the Members Committee, and the Markets, and Reliability Committee, as established in Sections 8.1 and 8.6.

1.41A.01 [Reserved].

1.41A.02 [Reserved].

1.41A.03 [Reserved].

1.41B Standing Committees.

"Standing Committees" shall mean the Members Committee, the committees established and maintained under Section 8.6, and such other committees as the Members Committee may establish and maintain from time to time.

1.42 State.

"State" shall mean the District of Columbia and any State or Commonwealth of the United States.

1.42.01 State Certification.

"State Certification" shall mean the Certification of an Authorized Commission, pursuant to Section 18 of this Agreement, the form of which is appended to this Agreement as Schedule 10A, wherein the Authorized Commission identifies all Authorized Persons employed or retained by such Authorized Commission, a copy of which shall be filed with FERC.

1.42A State Consumer Advocate.

"State Consumer Advocate" shall mean a legislatively created office from any State, all or any part of the territory of which is within the PJM Region, and the District of Columbia established,

inter alia, for the purpose of representing the interests of energy consumers before the utility regulatory commissions of such states and the District of Columbia and the FERC.

1.42A.01 Subregional RTEP Project.

"Subregional RTEP Project" shall mean a transmission expansion or enhancement rated below 230 kV which is requiredfor compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.

1.42A.02 Supplemental Project.

"Supplemental Project" shall mean a Regional RTEP Project(s) or Subregional RTEP Project(s), which is not required for compliance with the following PJM criteria: System reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.

1.42B ~~Synchronized Reserve Zone.~~ *[Reserved]*

~~"Synchronized Reserve Zone" shall mean any of those geographic areas consisting of a combination of one or more of the Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirement for, Synchronized Reserve service.~~

1.43 System.

"System" shall mean the interconnected electric supply system of a Member and its interconnected subsidiaries exclusive of facilities which it may own or control outside of the PJM Region. Each Member may include in its system the electric supply systems of any party or parties other than Members which are within the PJM Region, provided its interconnection agreements with such other party or parties do not conflict with such inclusion.

1.43A Third Party Request.

"Third Party Request" shall mean any request or demand by any entity upon an Authorized Person or an Authorized Commission for release or disclosure of confidential information provided to the Authorized Person or Authorized Commission by the Office of the Interconnection or PJM Market Monitor. A Third Party Request shall include, but shall not be limited to, any subpoena, discovery request, or other request for confidential information made by any: (i) federal, state, or local governmental subdivision, department, official, agency or court, or (ii) arbitration panel, business, company, entity or individual.

1.44 Transmission Facilities.

"Transmission Facilities" shall mean facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERC's Uniform System of Accounts or have

been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the transmission system of the PJM Region and integrated into the planning and operation of such to serve all of the power and transmission customers within such region.

1.45 Transmission Owner.

"Transmission Owner" shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

1.46 [Reserved.]

1.3 Definitions.

1.3.1 Acceleration Request.

"Acceleration Request" shall mean a request pursuant to section 1.9.4A of this Schedule to accelerate or reschedule a transmission outage scheduled pursuant to sections 1.9.2 or 1.9.4.

1.3.1A Auction Revenue Rights.

"Auction Revenue Rights" or "ARRs" shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Section 7.4 of this Schedule.

1.3.1B Auction Revenue Rights Credits.

"Auction Revenue Rights Credits" shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Section 7.4.3 of this Schedule.

1.3.1B.01 Batch Load Demand Resource.

"Batch Load Demand Resource" shall mean a Demand Resource that has a cyclical production process such that at most times during the process it is consuming energy, but at consistent regular intervals, ordinarily for periods of less than ten minutes, it reduces its consumption of energy for its production processes to minimal or zero megawatts.

1.3.1B.02 Congestion Price.

"Congestion Price" shall mean the congestion component of the Locational Marginal Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.1B.03 Curtailment Service Provider.

"Curtailment Service Provider" or "CSP" shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market by causing a reduction in demand.

1.3.1B.04 Day-ahead Congestion Price.

"Day-ahead Congestion Price" shall mean the Congestion Price resulting from the Day-ahead Energy Market.

1.3.1C Day-ahead Energy Market.

"Day-ahead Energy Market" shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Section 1.10 of this Schedule.

1.3.1C.01 Day-ahead Loss Price.

"Day-ahead Loss Price" shall mean the Loss Price resulting from the Day-ahead Energy Market.

1.3.1D Day-ahead Prices.

"Day-ahead Prices" shall mean the Locational Marginal Prices resulting from the Day-ahead Energy Market.

1.3.1D.01 Day-ahead Scheduling Reserves.

"Day-ahead Scheduling Reserves" shall mean thirty-minute reserves as defined by the Reliability First Corporation and SERC.

1.3.1D.02 Day-ahead Scheduling Reserves Requirement.

"Day-ahead Scheduling Reserves Requirement" shall mean the thirty-minute reserve requirement for the PJM Region established consistent with Reliability First Corporation and SERC reliability standards, or those of any additional and/or successor regional reliability organization(s) that are responsible for establishing reliability requirements for the PJM Region, plus any additional thirty-minute reserves scheduled in response to an RTO-wide Hot or Cold Weather Alert or other reasons for conservative operations.

1.3.1D.03 Day-ahead Scheduling Reserves Resources.

"Day-ahead Scheduling Reserves Resources" shall mean synchronized and non-synchronized generation resources and Demand Resources electrically located within the PJM Region that are capable of providing Day-ahead Scheduling Reserves.

1.3.1D.04 Day-ahead Scheduling Reserves Market.

"Day-ahead Scheduling Reserves Market" shall mean the schedule of commitments for the purchase or sale of Day-ahead Scheduling Reserves developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Section 1.10 of this Schedule.

1.3.1D.05 Day-ahead System Energy Price.

"Day-ahead System Energy Price" shall mean the System Energy Price resulting from the Day-ahead Energy Market.

1.3.1E Decrement Bid.

"Decrement Bid" shall mean a bid to purchase energy at a specified location in the Day-ahead Energy Market. An accepted Decrement Bid results in scheduled load at the specified location in the Day-ahead Energy Market.

1.3.1E.01 Demand Resource.

"Demand Resource" shall mean a resource with the capability to provide a reduction in demand.

1.3.1F Dispatch Rate.

"Dispatch Rate" shall mean the control signal, expressed in dollars per megawatt-hour, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by the Office of the Interconnection in accordance with the Offer Data.

1.3.1G Energy Storage Resource.

"Energy Storage Resource" shall mean flywheel or battery storage facility solely used for short term storage and injection of energy at a later time to participate in the PJM energy and/or Ancilliary Services markets as a Market Seller.

1.3.2 Equivalent Load.

"Equivalent Load" shall mean the sum of a Market Participant's net system requirements to serve its customer load in the PJM Region, if any, plus its net bilateral transactions.

1.3.2A Economic Load Response Participant.

"Economic Load Response Participant" shall mean a Member or Special Member that qualifies under Section 1.5A of this Schedule to participate in the PJM Interchange Energy Market through reductions in demand.

1.3.2A.01 Economic Minimum.

"Economic Minimum" shall mean the lowest incremental MW output level a unit can achieve while following economic dispatch.

1.3.2B Energy Market Opportunity Cost.

"Energy Market Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of available run hours due to limitations imposed on the unit by Applicable Laws and Regulations (as defined in PJM Tariff), and (b) the forecasted future hourly Locational Marginal Price at which the generating

unit could run while not violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Schedule 2 of the Operating Agreement.

1.3.3 External Market Buyer.

"External Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for consumption by end-users outside the PJM Region, or for load in the PJM Region that is not served by Network Transmission Service.

1.3.4 External Resource.

"External Resource" shall mean a generation resource located outside the metered boundaries of the PJM Region.

1.3.5 Financial Transmission Right.

"Financial Transmission Right" or "FTR" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2 of this Schedule.

1.3.5A Financial Transmission Right Obligation.

"Financial Transmission Right Obligation" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2(b) of this Schedule.

1.3.5B Financial Transmission Right Option.

"Financial Transmission Right Option" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2(c) of this Schedule.

1.3.6 Generating Market Buyer.

"Generating Market Buyer" shall mean an Internal Market Buyer that is a Load Serving Entity that owns or has contractual rights to the output of generation resources capable of serving the Market Buyer's load in the PJM Region, or of selling energy or related services in the PJM Interchange Energy Market or elsewhere.

1.3.7 Generator Forced Outage.

"Generator Forced Outage" shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the PJM Manuals. A reduction in output or

removal from service of a generating unit in response to changes in market conditions shall not constitute a Generator Forced Outage.

1.3.8 Generator Maintenance Outage.

"Generator Maintenance Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform necessary repairs on specific components of the facility, if removal of the facility meets the guidelines specified in the PJM Manuals.

1.3.9 Generator Planned Outage.

"Generator Planned Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the Office of the Interconnection in accordance with the PJM Manuals.

1.3.9A Increment Bid.

"Increment Bid" shall mean an offer to sell energy at a specified location in the Day-ahead Energy Market. An accepted Increment Bid results in scheduled generation at the specified location in the Day-ahead Energy Market.

1.3.9B Interface Pricing Point.

"Interface Pricing Point" shall have the meaning specified in section 2.6A.

1.3.10 Internal Market Buyer.

"Internal Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for ultimate consumption by end-users inside the PJM Region that are served by Network Transmission Service.

1.3.11 Inadvertent Interchange.

"Inadvertent Interchange" shall mean the difference between net actual energy flow and net scheduled energy flow into or out of the individual Control Areas operated by PJM.

1.3.11.01 Load Management.

"Load Management" shall mean either a Demand Resource ("DR") or an Interruptible Load for Reliability ("ILR") resource, both as defined in the Reliability Assurance Agreement.

1.3.11A Load Reduction Event.

"Load Reduction Event" shall mean a reduction in demand by a Member or Special Member for the purpose of participating in the PJM Interchange Energy Market.

1.3.11B Loss Price.

"Loss Price" shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.12 Market Operations Center.

"Market Operations Center" shall mean the equipment, facilities and personnel used by or on behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

1.3.12A Maximum Emergency.

"Maximum Emergency" shall mean the designation of all or part of the output of a generating unit for which the designated output levels may require extraordinary procedures and therefore are available to the Office of the Interconnection only when the Office of the Interconnection declares a Maximum Generation Emergency and requests generation designated as Maximum Emergency to run. The Office of the Interconnection shall post on the PJM website the aggregate amount of megawatts that are classified as Maximum Emergency.

1.3.13 Maximum Generation Emergency.

"Maximum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection to address either a generation or transmission emergency in which the Office of the Interconnection anticipates requesting one or more Generation Capacity Resources, or Non-Retail Behind The Meter Generation resources to operate at its maximum net or gross electrical power output, subject to the equipment stress limits for such Generation Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

1.3.14 Minimum Generation Emergency.

"Minimum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

1.3.14A NERC Interchange Distribution Calculator.

"NERC Interchange Distribution Calculator" shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

1.3.14B Net Benefits Test.

"Net Benefits Test" shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Section 3.3A.4 of this Schedule.

1.3.15 Network Resource.

"Network Resource" shall have the meaning specified in the PJM Tariff.

1.3.16 Network Service User.

"Network Service User" shall mean an entity using Network Transmission Service.

1.3.17 Network Transmission Service.

"Network Transmission Service" shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part III of the PJM Tariff, or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

1.3.17A Non-Regulatory Opportunity Cost.

"Non-Regulatory Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, (ii) a fuel supply limitation, for up to one year, resulting from an event of force majeure; and, (b) the forecasted future hourly Locational Marginal Price at which the generating unit could run while not violating such limitations. Non-Regulatory Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same period of time in which the unit is bound by the referenced restrictions, and is reflected in the rules set forth in PJM Manual 15. Non-Regulatory Opportunity Costs shall be limited to those resources which are specifically delineated in Schedule 2 of the Operating Agreement.

1.3.17B Non-Synchronized Reserve.

"Non-Synchronized Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

1.3.17C Non-Synchronized Reserve Event.

"Non-Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources and/or Demand Resources able, assigned or self-scheduled, to provide

Non-Synchronized Reserve within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-schedule Non-Synchronized Reserve capability.

1.3.17DB Non-Variable Loads.

"Non-Variable Loads" shall have the meaning specified in section 1.5A.6 of this Schedule.

1.3.18 Normal Maximum Generation.

"Normal Maximum Generation" shall mean the highest output level of a generating resource under normal operating conditions.

1.3.19 Normal Minimum Generation.

"Normal Minimum Generation" shall mean the lowest output level of a generating resource under normal operating conditions.

1.3.20 Offer Data.

"Offer Data" shall mean the scheduling, operations planning, dispatch, new resource, and other data and information necessary to schedule and dispatch generation resources and Demand Resource(s) for the provision of energy and other services and the maintenance of the reliability and security of the transmission system in the PJM Region, and specified for submission to the PJM Interchange Energy Market for such purposes by the Office of the Interconnection.

1.3.21 Office of the Interconnection Control Center.

"Office of the Interconnection Control Center" shall mean the equipment, facilities and personnel used by the Office of the Interconnection to coordinate and direct the operation of the PJM Region and to administer the PJM Interchange Energy Market, including facilities and equipment used to communicate and coordinate with the Market Participants in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

1.3.21A On-Site Generators.

"On-Site Generators" shall mean generation facilities (including Behind The Meter Generation) that (i) are not Capacity Resources, (ii) are not injecting into the grid, (iii) are either synchronized or non-synchronized to the Transmission System, and (iv) can be used to reduce demand for the purpose of participating in the PJM Interchange Energy Market.

1.3.22 Operating Day.

"Operating Day" shall mean the daily 24 hour period beginning at midnight for which transactions on the PJM Interchange Energy Market are scheduled.

1.3.23 Operating Margin.

"Operating Margin" shall mean the incremental adjustments, measured in megawatts, required in PJM Region operations in order to accommodate, on a first contingency basis, an operating contingency in the PJM Region resulting from operations in an interconnected Control Area. Such adjustments may result in constraints causing Transmission Congestion Charges, or may result in Ancillary Services charges pursuant to the PJM Tariff.

1.3.24 Operating Margin Customer.

"Operating Margin Customer" shall mean a Control Area purchasing Operating Margin pursuant to an agreement between such other Control Area and the LLC.

1.3.25 PJM Interchange.

"PJM Interchange" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load exceeds, or is exceeded by, the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup; or (c) the hourly scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the hourly net metered output of any other Market Seller; or (e) the hourly scheduled deliveries of Spot Market Energy to an External Market Buyer; or (f) the hourly scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

1.3.26 PJM Interchange Export.

"PJM Interchange Export" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load is exceeded by the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup sales; or (c) the hourly scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the hourly net metered output of any other Market Seller.

1.3.27 PJM Interchange Import.

"PJM Interchange Import" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load exceeds the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup purchases; or (c) the hourly scheduled deliveries of Spot Market Energy to an External Market Buyer; or (d) the hourly scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

1.3.28 PJM Open Access Same-time Information System.

"PJM Open Access Same-time Information System" shall mean the electronic communication system for the collection and dissemination of information about transmission services in the PJM Region, established and operated by the Office of the Interconnection in accordance with FERC standards and requirements.

1.3.28A Planning Period Quarter.

"Planning Period Quarter" shall mean any of the following three month periods in the Planning Period: June, July and August; September, October and November; December, January and February; or March, April and May.

1.3.28B Planning Period Balance.

"Planning Period Balance" shall mean the entire period of time remaining in the Planning Period following the month that a monthly auction is conducted.

1.3.29 Point-to-Point Transmission Service.

"Point-to-Point Transmission Service" shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part II of the PJM Tariff.

1.3.29A PRD Curve

PRD Curve shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29B PRD Provider

PRD Provider shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29C PRD Reservation Price

PRD Reservation Price shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29D PRD Substation

PRD Substation shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29E Price Responsive Demand

Price Responsive Demand shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29F Primary Reserve

"Primary Reserve" shall mean the total reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes of a request from the Office of the Interconnection dispatcher, and is comprised of both Synchronized Reserve and Non-Synchronized Reserve.

1.3.30 Ramping Capability.

"Ramping Capability" shall mean the sustained rate of change of generator output, in megawatts per minute.

1.3.30.01 Real-time Congestion Price.

"Real-time Congestion Price" shall mean the Congestion Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30.02 Real-time Loss Price.

"Real-time Loss Price" shall mean the Loss Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30A Real-time Prices.

"Real-time Prices" shall mean the Locational Marginal Prices resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30B Real-time Energy Market.

"Real-time Energy Market" shall mean the purchase or sale of energy and payment of Transmission Congestion Charges for quantity deviations from the Day-ahead Energy Market in the Operating Day.

1.3.30B.01 Real-time System Energy Price.

"Real-time System Energy Price" shall mean the System Energy Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.31 Regulation.

"Regulation" shall mean the capability of a specific generation resource or Demand Resource with appropriate telecommunications, control and response capability to increase or decrease its output or adjust load in response to a regulating control signal, in accordance with the specifications in the PJM Manuals.

1.3.31.001 Reserve Penalty Factor.

"Reserve Penalty Factor" shall mean the cost, in $/MWh, associated with being unable to meet a specific reserve requirement in a Reserve Zone. A Reserve Penalty Factor will be defined for each reserve requirement in a Reserve Zone.

1.3.31.01 Residual Auction Revenue Rights.

"Residual Auction Revenue Rights" shall mean incremental stage 1 Auction Revenue Rights created within a Planning Period by an increase in transmission system capability or a change in any other relevant factor that was not modeled pursuant to section 7.5 of Schedule 1 of this Agreement in compliance with section 7.4.2(h) of Schedule 1 of this Agreement, and, if modeled, would have increased the amount of stage 1 Auction Revenue Rights allocated pursuant to section 7.4.2 of Schedule 1 of this Agreement; provided that, the foregoing notwithstanding, Residual Auction Revenue Rights shall exclude: 1) Incremental Auction Revenue Rights allocated pursuant to Part VI of the Tariff; and 2) Auction Revenue Rights allocated to entities that are assigned cost responsibility pursuant to Schedule 6 of this Agreement for transmission upgrades that create such rights.

1.3.31.02 Special Member.

"Special Member" shall mean an entity that satisfies the requirements of Section 1.5A.02 of this Schedule or the special membership provisions established under the Emergency Load Response Program.

1.3.31A [Reserved.]

1.3.31B [Reserved.]

1.3.32 Spot Market Backup.

"Spot Market Backup" shall mean the purchase of energy from, or the delivery of energy to, the PJM Interchange Energy Market in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason.

1.3.33 Spot Market Energy.

"Spot Market Energy" shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at System Energy Prices determined as specified in Section 2 of this Schedule.

1.3.33A State Estimator.

"State Estimator" shall mean the computer model of power flows specified in Section 2.3 of this Schedule.

1.3.33B Station Power.

"Station Power" shall mean energy used for operating the electric equipment on the site of a generation facility located in the PJM Region or for the heating, lighting, air-conditioning and office equipment needs of buildings on the site of such a generation facility that are used in the operation, maintenance, or repair of the facility. Station Power does not include any energy (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility; (iii) used for compressors at a compressed air energy storage facility; (iv) used for charging an Energy Storage Resource; or (v) used in association with restoration or black start service.

1.3.33B.01 Synchronized Reserve.

"Synchronized Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes from the request of the Office of the Interconnection dispatcher, and is provided by equipment that is electrically synchronized to the Transmission System.

1.3.33B.02 Synchronized Reserve Event.

"Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources and/or Demand Resources able, assigned or self-scheduled to provide Synchronized Reserve, within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-scheduled Synchronized Reserve capability.

1.3.33B.03 System Energy Price.

"System Energy Price" shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.33C Target Allocation.

"Target Allocation" shall mean the allocation of Transmission Congestion Credits as set forth in Section 5.2.3 of this Schedule or the allocation of Auction Revenue Rights Credits as set forth in Section 7.4.3 of this Schedule.

1.3.34 Transmission Congestion Charge.

"Transmission Congestion Charge" shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses in accordance with Section 9.3, which shall be calculated and allocated as specified in Section 5.1 of this Schedule.

1.3.35 Transmission Congestion Credit.

"Transmission Congestion Credit" shall mean the allocated share of total Transmission Congestion Charges credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section 5.2 of this Schedule.

1.3.36 Transmission Customer.

"Transmission Customer" shall mean an entity using Point-to-Point Transmission Service.

1.3.37 Transmission Forced Outage.

"Transmission Forced Outage" shall mean an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the PJM Manuals. A removal from service of a transmission facility at the request of the Office of the Interconnection to improve transmission capability shall not constitute a Forced Transmission Outage.

1.3.37A Transmission Loading Relief.

"Transmission Loading Relief" shall mean NERC's procedures for preventing operating security limit violations, as implemented by PJM as the security coordinator responsible for maintaining transmission security for the PJM Region.

1.3.37B Transmission Loading Relief Customer.

"Transmission Loading Relief Customer" shall mean an entity that, in accordance with Section 1.10.6A, has elected to pay Transmission Congestion Charges during Transmission Loading Relief in order to continue energy schedules over contract paths outside the PJM Region that are increasing the cost of energy in the PJM Region.

1.3.37C Transmission Loss Charge.

"Transmission Loss Charge" shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Section 5 of this Schedule.

1.3.38 Transmission Planned Outage.

"Transmission Planned Outage" shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in this Agreement or the PJM Manuals.

1.3.38A Variable Loads.

"Variable Loads" shall have the meaning specified in section 1.5A.6 of this Schedule.

1.3.39 Zonal Base Load.

"Zonal Base Load" shall mean the lowest daily zonal peak load from the twelve month period ending October 21 of the calendar year immediately preceding the calendar year in which an annual Auction Revenue Right allocation is conducted, increased by the projected load growth rate for the relevant Zone.

1.7 General.

1.7.1 Market Sellers.

Only Market Sellers shall be eligible to submit offers to the Office of the Interconnection for the sale of electric energy or related services in the PJM Interchange Energy Market. Market Sellers shall comply with the prices, terms, and operating characteristics of all Offer Data submitted to and accepted by the PJM Interchange Energy Market.

1.7.2 Market Buyers.

Only Market Buyers shall be eligible to purchase energy or related services in the PJM Interchange Energy Market. Market Buyers shall comply with all requirements for making purchases from the PJM Interchange Energy Market.

1.7.2A Economic Load Response Participants.

Only Economic Load Response Participants shall be eligible to participate in the Real-time Energy Market and the Day-ahead Energy Market by submitting offers to the Office of the Interconnection to reduce demand.

1.7.3 Agents.

A Market Participant may participate in the PJM Interchange Energy Market through an agent, provided that the Market Participant informs the Office of the Interconnection in advance in writing of the appointment of such agent. A Market Participant participating in the PJM Interchange Energy Market through an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the PJM Interchange Energy Market, and shall ensure that any such agent complies with the requirements of this Agreement.

1.7.4 General Obligations of the Market Participants.

(a) In performing its obligations to the Office of the Interconnection hereunder, each Market Participant shall at all times (i) follow Good Utility Practice, (ii) comply with all applicable laws and regulations, (iii) comply with the applicable principles, guidelines, standards and requirements of FERC, NERC and Applicable Regional Reliability Councils, (iv) comply with the procedures established for operation of the PJM Interchange Energy Market and PJM Region and (v) cooperate with the Office of the Interconnection as necessary for the operation of the PJM Region in a safe, reliable manner consistent with Good Utility Practice.

(b) Market Participants shall undertake all operations in or affecting the PJM Interchange Energy Market and the PJM Region including but not limited to compliance with all Emergency procedures, in accordance with the power and authority of the Office of the Interconnection with respect to the operation of the PJM Interchange Energy Market and the PJM Region as established in this Agreement, and as specified in the Schedules to this Agreement and the PJM Manuals. Failure to comply with the foregoing operational requirements shall subject a Market

Participant to such reasonable charges or other remedies or sanctions for non-compliance as may be established by the PJM Board, including legal or regulatory proceedings as authorized by the PJM Board to enforce the obligations of this Agreement.

(c) The Office of the Interconnection may establish such committees with a representative of each Market Participant, and the Market Participants agree to provide appropriately qualified personnel for such committees, as may be necessary for the Office of the Interconnection and PJMSettlement to perform its obligations hereunder.

(d) All Market Participants shall provide to the Office of the Interconnection the scheduling and other information specified in the Schedules to this Agreement, and such other information as the Office of the Interconnection may reasonably require for the reliable and efficient operation of the PJM Region and PJM Interchange Energy Market, and for compliance with applicable regulatory requirements for posting market and related information. Such information shall be provided as much in advance as possible, but in no event later than the deadlines established by the Schedules to this Agreement, or by the Office of the Interconnection in conformance with such Schedules. Such information shall include, but not be limited to, maintenance and other anticipated outages of generation or transmission facilities, scheduling and related information on bilateral transactions and self-scheduled resources, and implementation of active load management, interruption of load, Price Responsive Demand, and other load reduction measures. The Office of the Interconnection shall abide by appropriate requirements for the non-disclosure and protection of any confidential or proprietary information given to the Office of the Interconnection by a Market Participant. Each Market Participant shall maintain or cause to be maintained compatible information and communications systems, as specified by the Office of the Interconnection, required to transmit scheduling, dispatch, or other time-sensitive information to the Office of the Interconnection in a timely manner.

(e) Subject to the requirements for Economic Load Response participants in section 1.5A above, each Market Participant shall install and operate, or shall otherwise arrange for, metering and related equipment capable of recording and transmitting all voice and data communications reasonably necessary for the Office of the Interconnection and PJMSettlement to perform the services specified in this Agreement. A Market Participant that elects to be separately billed for its PJM Interchange shall, to the extent necessary, be individually metered in accordance with Section 14 of this Agreement, or shall agree upon an allocation of PJM Interchange between it and the Market Participant through whose meters the unmetered Market Participant's PJM Interchange is delivered. The Office of the Interconnection shall be notified of the allocation by the foregoing Market Participants.

(f) Each Market Participant shall operate, or shall cause to be operated, any generating resources owned or controlled by such Market Participant that are within the PJM Region or otherwise supplying energy to or through the PJM Region in a manner that is consistent with the standards, requirements or directions of the Office of the Interconnection and that will permit the Office of the Interconnection to perform its obligations under this Agreement; provided, however, no Market Participant shall be required to take any action that is inconsistent with Good Utility Practice or applicable law.

(g) Each Market Participant shall follow the directions of the Office of the Interconnection to take actions to prevent, manage, alleviate or end an Emergency in a manner consistent with this Agreement and the procedures of the PJM Region as specified in the PJM Manuals.

(h) Each Market Participant shall obtain and maintain all permits, licenses or approvals required for the Market Participant to participate in the PJM Interchange Energy Market in the manner contemplated by this Agreement.

(i) Consistent with Section 36.1.1 of the PJM Tariff, to the extent its generating facility is dispatchable, a Market Participant shall submit an Economic Minimum in the Real-time Energy Market that is no greater than the higher of its physical operating minimum or its Capacity Interconnection Rights, as that term is defined in the PJM Tariff, associated with such generating facility under its Interconnection Service Agreement under Attachment O of the PJM Tariff or a wholesale market participation agreement.

1.7.5 Market Operations Center.

Each Market Participant shall maintain a Market Operations Center, or shall make appropriate arrangements for the performance of such services on its behalf. A Market Operations Center shall meet the performance, equipment, communications, staffing and training standards and requirements specified in this Agreement for the scheduling and completion of transactions in the PJM Interchange Energy Market and the maintenance of the reliable operation of the PJM Region, and shall be sufficient to enable (i) a Market Seller or an Economic Load Response Participant to perform all terms and conditions of its offers to the PJM Interchange Energy Market, and (ii) a Market Buyer or an Economic Load Response Participant to conform to the requirements for purchasing from the PJM Interchange Energy Market.

1.7.6 Scheduling and Dispatching.

(a) The Office of the Interconnection shall schedule and dispatch in real-time generation resources and/or Demand Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Sellers, continuing until sufficient generation resources and/or Demand Resources are dispatched to serve the PJM Interchange Energy Market energy purchase requirements under normal system conditions of the Market Buyers (taking into account any reductions to such requirements in accordance with PRD Curves properly submitted by PRD Providers), as well as the requirements of the PJM Region for ancillary services provided by generation resources and/or Demand Resources, in accordance with this Agreement. Such scheduling and dispatch shall recognize transmission constraints on coordinated flowgates external to the Transmission System in accordance with Appendix A to the Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38) and on other such flowgates that are coordinated in accordance with agreements between the LLC and other entities. Scheduling and dispatch shall be conducted in accordance with this Agreement.

(b) The Office of the Interconnection shall undertake to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the PJM Interchange Energy Market, and any relevant procedures of another Control Area, or any tariff (including the PJM Tariff). Upon determining that any such conflict or incompatibility exists, the Office of the Interconnection shall propose tariff or procedural changes, and undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

(c) To protect its generation or distribution facilities, or local Transmission Facilities not under the monitoring responsibility and dispatch control of the Office of the Interconnection, an entity may request that the Office of the Interconnection schedule and dispatch generation or reductions in demand to meet a limit on Transmission Facilities different from that which the Office of the Interconnection has determined to be required for reliable operation of the Transmission System. To the extent consistent with its other obligations under this Agreement, the Office of the Interconnection shall schedule and dispatch generation and reductions in demand in accordance with such request. An entity that makes a request pursuant to this section 1.7.6(c) shall be responsible for all generation and other costs resulting from its request that would not have been incurred by operating the Transmission System and scheduling and dispatching generation in the manner that the Office of the Interconnection otherwise has determined to be required for reliable operation of the Transmission System.

1.7.7 Pricing.

The price paid for energy bought and sold in the PJM Interchange Energy Market and for demand reductions will reflect the hourly Locational Marginal Price at each load and generation bus, determined by the Office of the Interconnection in accordance with this Agreement. Transmission Congestion Charges and Transmission Loss Charges, which shall be determined by differences in Congestion Prices and Loss Prices in an hour, shall be calculated by the Office of the Interconnection, and collected by PJMSettlement, and the revenues therefrom shall be disbursed by PJMSettlement in accordance with this Schedule.

1.7.8 Generating Market Buyer Resources.

A Generating Market Buyer may elect to self-schedule its generation resources up to that Generating Market Buyer's Equivalent Load, in accordance with and subject to the procedures specified in this Schedule, and the accounting and billing requirements specified in Section 3 to this Schedule. PJMSettlement shall not be a contracting party with respect to such self-scheduled or self-supplied transactions.

1.7.9 Delivery to an External Market Buyer.

A purchase of Spot Market Energy by an External Market Buyer shall be delivered to a bus or buses at the electrical boundaries of the PJM Region specified by the Office of the Interconnection, or to load in such area that is not served by Network Transmission Service, using Point-to-Point Transmission Service paid for by the External Market Buyer. Further delivery of such energy shall be the responsibility of the External Market Buyer.

1.7.10 Other Transactions.

(a) Bilateral Transactions.

(i) In addition to transactions in the PJM Interchange Energy Market, Market Participants may enter into bilateral contracts for the purchase or sale of electric energy to or from each other or any other entity, subject to the obligations of Market Participants to make Generation Capacity Resources available for dispatch by the Office of the Interconnection. Such bilateral contracts shall be for the physical transfer of energy to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its eSchedules and Enhanced Energy Scheduler tools.

(ii) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of energy to a Market Participant inside the PJM Region, title to the energy that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and the further transmission of the energy or further sale of the energy into the PJM Interchange Energy Market shall be transacted by the buyer under the bilateral contract. With respect to all bilateral contracts for the physical transfer of energy to an entity outside the PJM Region, title to the energy shall pass to the buyer at the border of the PJM Region and shall be delivered to the border using transmission service. In no event shall the purchase and sale of energy between Market Participants under a bilateral contract constitute a transaction in the PJM Interchange Energy Market or be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

(iii) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of energy reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the megawatt hours of such reported transactions to amounts reflecting the expected load and other physical delivery obligations of the buyer under the bilateral contract.

(iv) All payments and related charges for the energy associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. 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 a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

(v) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any Spot Market Backup used to meet the bilateral contract seller's obligation to deliver energy under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new eSchedules or Enhanced Energy Scheduler reporting by the Market Participant and (ii) terminate all of the Market Participant's eSchedules and Enhanced Energy Schedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the eSchedules and Enhanced Energy Schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection. PJMSettlement shall assign its claims against a seller with respect to a seller's nonpayment for Spot Market Backup to a buyer the extent that the buyer has made an indemnification payment to PJMSettlement with respect to the seller's nonpayment.

(vi) Bilateral contracts that do not contemplate the physical transfer of energy to or from a Market Participant are not subject to this Schedule, shall not be reported to and coordinated with the Office of the Interconnection, and shall not in any way constitute a transaction in the PJM Interchange Energy Market.

(b) Market Participants shall have Spot Market Backup with respect to all bilateral transactions that contemplate the physical transfer of energy to or from a Market Participant, that are not dynamically scheduled pursuant to Section 1.12 and that are curtailed or interrupted for any reason (except for curtailments or interruptions through active load management for load located within the PJM Region).

(c) To the extent the Office of the Interconnection dispatches a Generating Market Buyer's generation resources, such Generating Market Buyer may elect to net the output of such resources against its hourly Equivalent Load. Such a Generating Market Buyer shall be deemed a buyer from the PJM Interchange Energy Market to the extent of its PJM Interchange Imports, and shall be deemed a seller to the PJM Interchange Energy Market to the extent of its PJM Interchange Exports.

(d) A Market Seller may self-supply Station Power for its generation facility in accordance with the following provisions:

(i) A Market Seller may self-supply Station Power for its generation facility during any month (1) when the net output of such facility is positive, or (2) when the net output of such facility is negative and the Market Seller during the same month has available at other of its generation facilities positive net output in an amount at least sufficient to offset fully such negative net output. For purposes of this subsection (d), "net output" of a generation facility during any month means the facility's gross energy output, less the Station Power requirements of such facility, during that month. The determination of a generation facility's or a Market Seller's monthly net output under this subsection (d) will apply only to determine whether the Market Seller self-supplied Station Power during the month and will not affect the price of energy sold or consumed by the Market Seller at any bus during any hour during the month. For each hour when a Market Seller has positive net output and delivers energy into the Transmission System, it will be paid the LMP at its bus for that hour for all of the energy delivered. Conversely, for each hour when a Market Seller has negative net output and has received Station Power from the Transmission System, it will pay the LMP at its bus for that hour for all of the energy consumed.

(ii) Transmission Provider will determine the extent to which each affected Market Seller during the month self-supplied its Station Power requirements or obtained Station Power from third-party providers (including affiliates) and will incorporate that determination in its accounting and billing for the month. In the event that a Market Seller self-supplies Station Power during any month in the manner described in subsection (1) of subsection (d)(i) above, Market Seller will not use, and will not incur any charges for, transmission service. In the event, and to the extent, that a Market Seller self-supplies Station Power during any month in the manner described in subsection (2) of subsection (d)(i) above (hereafter referred to as "remote self-supply of Station Power"), Market Seller shall use and pay for transmission service for the transmission of energy in an amount equal to the facility's negative net output from Market Seller's generation facility(ies) having positive net output. Unless the Market Seller makes other arrangements with Transmission Provider in advance, such transmission service shall be provided under Part II of the PJM Tariff and shall be charged the hourly rate under Schedule 8 of the PJM Tariff for Non-Firm Point-to-Point Transmission Service with an election to pay congestion charges, provided, however, that no reservation shall be necessary for such transmission service and the terms and charges under Schedules 1, 1A, 2 through 6, 9 and 10 of the PJM Tariff shall not apply to such service. The amount of energy that a Market Seller transmits in conjunction with remote self-supply of Station Power will not be affected by any other sales, purchases, or transmission of capacity or energy by or for such Market Seller under any other provisions of the PJM Tariff.

(iii) A Market Seller may self-supply Station Power from its generation facilities located outside of the PJM Region during any month only if such generation facilities in fact run during such month and Market Seller separately has reserved transmission service and scheduled delivery of the energy from such resource in advance into the PJM Region.

1.7.11 Emergencies.

(a) The Office of the Interconnection, with the assistance of the Members' dispatchers as it may request, shall be responsible for monitoring the operation of the PJM Region, for declaring the existence of an Emergency, and for directing the operations of Market Participants as necessary to manage, alleviate or end an Emergency. The standards, policies and procedures of the Office of the Interconnection for declaring the existence of an Emergency, including but not limited to a Minimum Generation Emergency, and for managing, alleviating or ending an Emergency, shall apply to all Members on a non-discriminatory basis. Actions by the Office of the Interconnection and the Market Participants shall be carried out in accordance with this Agreement, the NERC Operating Policies, Applicable Regional Reliability Council reliability principles and standards, Good Utility Practice, and the PJM Manuals. A declaration that an Emergency exists or is likely to exist by the Office of the Interconnection shall be binding on all Market Participants until the Office of the Interconnection announces that the actual or threatened Emergency no longer exists. Consistent with existing contracts, all Market Participants shall comply with all directions from the Office of the Interconnection for the purpose of managing, alleviating or ending an Emergency. The Market Participants shall authorize the Office of the Interconnection and PJMSettlement to purchase or sell energy on their behalf to meet an Emergency, and otherwise to implement agreements with other Control Areas interconnected with the PJM Region for the mutual provision of service to meet an Emergency, in accordance with this Agreement.

(b) To the extent load must be shed to alleviate an Emergency in a Control Zone, the Office of the Interconnection shall, to the maximum extent practicable, direct the shedding of load within such Control Zone. The Office of the Interconnection may shed load in one Control Zone to alleviate an Emergency in another Control Zone under its control only as necessary after having first shed load to the maximum extent practicable in the Control Zone experiencing the Emergency and only to the extent that PJM supports other control areas (not under its control) in those situations where load shedding would be necessary, such as to prevent isolation of facilities within the Eastern Interconnection, to prevent voltage collapse, or to restore system frequency following a system collapse; provided, however, that the Office of the Interconnection may not order a manual load dump in a Control Zone solely to address capacity deficiencies in another Control Zone. This subsection shall be implemented consistent with North American Electric Reliability Council and applicable reliability council standards.

1.7.12 Fees and Charges.

Each Market Participant, except for Special Members, shall pay all fees and charges of the Office of the Interconnection for operation of the PJM Interchange Energy Market as determined

by and allocated to the Market Participant by the Office of the Interconnection in accordance with Schedule 3.

1.7.13 Relationship to the PJM Region.

The PJM Interchange Energy Market operates within and subject to the requirements for the operation of the PJM Region.

1.7.14 PJM Manuals.

The Office of the Interconnection shall be responsible for maintaining, updating, and promulgating the PJM Manuals as they relate to the operation of the PJM Interchange Energy Market. The PJM Manuals, as they relate to the operation of the PJM Interchange Energy Market, shall conform and comply with this Agreement, NERC operating policies, and Applicable Regional Reliability Council reliability principles, guidelines and standards, and shall be designed to facilitate administration of an efficient energy market within industry reliability standards and the physical capabilities of the PJM Region.

1.7.15 Corrective Action.

Consistent with Good Utility Practice, the Office of the Interconnection shall be authorized to direct or coordinate corrective action, whether or not specified in the PJM Manuals, as necessary to alleviate unusual conditions that threaten the integrity or reliability of the PJM Region, or the regional power system.

1.7.16 Recording.

Subject to the requirements of applicable State or federal law, all voice communications with the Office of the Interconnection Control Center may be recorded by the Office of the Interconnection and any Market Participant communicating with the Office of the Interconnection Control Center, and each Market Participant hereby consents to such recording.

1.7.17 Operating Reserves.

(a) The following procedures shall apply to any generation unit subject to the dispatch of the Office of the Interconnection for which construction commenced before July 9, 1996, or any Demand Resource subject to the dispatch of the Office of the Interconnection.

(b) The Office of the Interconnection shall schedule to the Operating Reserve and load-following objectives of the Control Zones of the PJM Region and the PJM Interchange Energy Market in scheduling generation resources and/or Demand Resources pursuant to this Schedule. A table of Operating Reserve objectives for each Control Zone is calculated and published annually in the PJM Manuals. Reserve levels are probabilistically determined based on the season's historical load forecasting error and forced outage rates.

(c) Nuclear generation resources shall not be eligible for Operating Reserve payments unless: 1) the Office of the Interconnection directs such resources to reduce output, in which case, such units shall be compensated in accordance with section 3.2.3(f) of this Schedule; or 2) the resource submits a request for a risk premium to the Market Monitoring Unit under the procedures specified in Section II.B of Attachment M - Appendix. A nuclear generation resource (i) must submit a risk premium consistent with its agreement under such process, or, (ii) if it has not agreed with the Market Monitoring Unit on an appropriate risk premium, may submit its own determination of an appropriate risk premium to the Office of the Interconnection, subject to acceptance by the Office of the Interconnection, with or without prior approval from the Commission.

(d) PJMSettlement shall be the Counterparty to the purchases and sales of Operating Reserve in the PJM Interchange Energy Market.

1.7.18 Regulation.

(a) Regulation to meet the Regulation objective of each Regulation Zone shall be supplied from generation resources and/or Demand Resources located within the metered electrical boundaries of such Regulation Zone. Generating Market Buyers, and Market Sellers offering Regulation, shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the PJM Manuals.

(b) The Office of the Interconnection shall obtain and maintain for each Regulation Zone an amount of Regulation equal to the Regulation objective for such Regulation Zone as specified in the PJM Manuals.

(c) The Regulation range of a generation unit or Demand Resource shall be at least twice the amount of Regulation assigned as described in the PJM Manuals.

(d) A ~~generation unit~~resource capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced by at least twice the amount of the Regulation provided with consideration of . ~~T~~the ~~amount of~~ Regulation ~~provided by a generation unit shall serve to redefine the Normal Minimum Generation and Normal Maximum Generation energy~~ limits of that ~~generation unit~~resource, ~~in that the amount of Regulation shall be added to the generation unit's Normal Minimum Generation energy limit, and subtracted from its Normal Maximum Generation energy limit~~ as specified in the PJM Manuals.

(e) Qualified Regulation must satisfy the verification tests described in the PJM Manuals.

1.7.19 Ramping.

A generator dispatched by the Office of the Interconnection pursuant to a control signal appropriate to increase or decrease the generator's megawatt output level shall be able to change output at the ramping rate specified in the Offer Data submitted to the Office of the Interconnection for that generator.

1.7.19A Synchronized Reserve.

(a) Synchronized Reserve shall be supplied from generation resources and/or Demand Resources located within the metered boundaries of the PJM Region. Generating Market Buyers, and Market Sellers offering Synchronized Reserve shall comply with applicable standards and requirements for Synchronized Reserve capability and dispatch specified in the PJM Manuals.

(b) The Office of the Interconnection shall obtain and maintain for each ~~Synchronized~~ Reserve Zone an amount of *Primary and* Synchronized Reserve equal to the *respective Primary and* Synchronized Reserve objectives for such ~~Synchronized~~ Reserve Zone, as specified in the PJM Manuals.

(c) The Synchronized Reserve capability of a generation resource and Demand Resource shall be the increase in energy output or load reduction achievable by the generation resource and Demand Resource within a continuous 10-minute period.

(d) A generation unit capable of automatic energy dispatch that also is providing Synchronized Reserve shall have its energy dispatch range reduced by the amount of the Synchronized Reserve provided. The amount of Synchronized Reserve provided by a generation unit shall serve to redefine the Normal Maximum Generation energy limit of that generation unit in that the amount of Synchronized Reserve provided shall be subtracted from its Normal Maximum Generation energy limit.

1.7.19A.01 Non-Synchronized Reserve.

(a) Non-Synchronized Reserve shall be supplied from generation resources and/or Demand Resources located within the metered boundaries of the PJM Region. Generating Market Buyers and Market Sellers offering Non-Synchronized Reserve shall comply with applicable standards and requirements for Non-Synchronized Reserve capability and dispatch specified in the PJM Manuals.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone an amount of Non-Synchronized Reserve such that the sum of the Synchronized Reserve and Non-Synchronized Reserve meets the Primary Reserve objective for such Reserve Zone, as specified in the PJM Manuals.

(c) The Non-Synchronized Reserve capability of a generation resource and Demand Resource shall be the increase in energy output or load reduction achievable by the generation resource and Demand Resource within a continuous 10-minute period provided that the resource is not synchronized to the system at the initiation of the response.

1.7.19B Bilateral Transactions Regarding Regulation, Synchronized Reserve and Day-ahead Scheduling Reserves.

(a) In addition to transactions in the Regulation market, Synchronized Reserve market, and Day-ahead Scheduling Reserves Market, Market Participants may enter into bilateral contracts for the purchase or sale of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from each other or any other entity. Such bilateral contracts shall be for the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its eMarket tools.

(b) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to a Market Participant in the PJM Region, title to the product that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and any further transactions associated with such products or further sale of such Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves in the markets for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves, respectively, shall be transacted by the buyer under the bilateral contract. In no event shall the purchase and sale of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves between Market Participants under a bilateral contract constitute a transaction in PJM's markets for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves, or otherwise construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

(c) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the amounts of such reported transactions to amounts reflecting the expected requirements for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves of the buyer pursuant to such bilateral contracts.

(d) All payments and related charges for the Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection. The LLC, PJM Settlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

(e) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any purchases by the seller under the bilateral contract in the markets for Regulations, Synchronized Reserve, or Day-ahead Scheduling Reserves used to meet the bilateral contract seller's obligation to deliver Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new eMarket reporting by the Market Participant and (ii) terminate all of the Market

Participant's reporting of eMarkets schedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the reported eMarkets schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection.

(f) Market Participants shall purchase Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves from PJM's markets for Regulation, Synchronized Reserve, Day-ahead Scheduling Reserves, in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason, with respect to all bilateral transactions that contemplate the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from a Market Participant.

1.7.20 Communication and Operating Requirements.

(a) Market Participants. Each Market Participant shall have, or shall arrange to have, its transactions in the PJM Interchange Energy Market subject to control by a Market Operations Center, with staffing and communications systems capable of real-time communication with the Office of the Interconnection during normal and Emergency conditions and of control of the Market Participant's relevant load or facilities sufficient to meet the requirements of the Market Participant's transactions with the PJM Interchange Energy Market, including but not limited to the following requirements as applicable.

(b) Market Sellers selling from generation resources and/or Demand Resources within the PJM Region shall: report to the Office of the Interconnection sources of energy and Demand Resources available for operation; supply to the Office of the Interconnection all applicable Offer Data; report to the Office of the Interconnection generation resources that are self-scheduled; with respect to generation resources, report to the Office of the Interconnection bilateral sales transactions to buyers not within the PJM Region; confirm to the Office of the Interconnection bilateral sales to Market Buyers within the PJM Region; respond to the Office of the Interconnection's directives to start, shutdown or change output levels of generation units, or change scheduled voltages or reactive output levels of generation units, or reduce load from Demand Resources; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, generating equipment and Demand Resources are operated with control equipment functioning as specified in the PJM Manuals.

(c) Market Sellers selling from generation resources outside the PJM Region shall: provide to the Office of the Interconnection all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to Office of the Interconnection directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the Market Seller's Control Area.

(d) Market Participants that are Load Serving Entities or purchasing on behalf of Load Serving Entities shall: respond to Office of the Interconnection directives for load management

steps; report to the Office of the Interconnection Generation Capacity Resources to satisfy capacity obligations that are available for pool operation; report to the Office of the Interconnection all bilateral purchase transactions; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(e) Market Participants that are not Load Serving Entities or purchasing on behalf of Load Serving Entities shall: provide to the Office of the Interconnection requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the PJM Interchange Energy Market, along with Dispatch Rate levels above which it does not desire to purchase; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(f) Economic Load Response Participants are responsible for maintaining demand reduction information, including the amount and price at which demand may be reduced. The Economic Load Response Participant shall provide this information to the Office of the Interconnection by posting it on the Load Response Program Registration link of the PJM website as required by the PJM Manuals. The Economic Load Response Participant shall notify the Office of the Interconnection of a demand reduction concurrent with, or prior to, the beginning of such demand reduction in accordance with the PJM Manuals. In the event that an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer that would affect a relevant Customer Baseline Load as required by the PJM Manuals.

(g) PRD Providers shall be responsible for ensuring automated reductions to their Price Responsive Demand in response to price in accordance with their PRD Curves submitted to the Office of the Interconnection.

1.10 Scheduling.

1.10.1 General.

(a) The Office of the Interconnection shall administer scheduling processes to implement a Day-ahead Energy Market and a Real-time Energy Market. PJMSettlement shall be the Counterparty to the purchases and sales of energy that clear the Day-ahead Energy Market and the Real-time Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a Generating Market Buyer's self-schedule or self-supply of its generation resources up to that Generating Market Buyer's Equivalent Load.

(b) The Day-ahead Energy Market shall enable Market Participants to purchase and sell energy through the PJM Interchange Energy Market at Day-ahead Prices and enable Transmission Customers to reserve transmission service with Transmission Congestion Charges and Transmission Loss Charges based on locational differences in Day-ahead Prices. Up-To Congestion transactions submitted in the Day-ahead Energy Market shall not require transmission service and Transmission Customers shall not reserve transmission service for such transactions. Market Participants whose purchases and sales, and Transmission Customers whose transmission uses are scheduled in the Day-ahead Energy Market, shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, at the applicable Day-ahead Prices for the amounts scheduled.

(c) In the Real-time Energy Market, Market Participants that deviate from the amounts of energy purchases or sales, or Transmission Customers that deviate from the transmission uses, scheduled in the Day-ahead Energy Market shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling shall be conducted as specified below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM Manuals.

1.10.1A Day-ahead Energy Market Scheduling.

The following actions shall occur not later than 12:00 noon on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the Office of the Interconnection in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Schedule.

(a) Each Market Participant may submit to the Office of the Interconnection specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the PJM Manuals. Each Market Buyer shall inform the Office of the Interconnection of the prices, if any, at which it desires not to include its load in the Day-ahead Energy Market rather than pay the Day-ahead Price. PRD Providers that have committed Price Responsive Demand in accordance with the Reliability Assurance Agreement shall submit to the Office of the Interconnection, in accordance with procedures specified in the PJM Manuals, any desired updates to their previously submitted PRD Curves, provided that such updates are consistent with their Price Responsive Demand commitments, and provided further that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue may only submit PRD Curves for the Real-time Energy Market. Price Responsive Demand that has been committed in accordance with the Reliability Assurance Agreement shall be presumed available for the next Operating Day in accordance with the most recently submitted PRD Curve unless the PRD Curve is updated to indicate otherwise. PRD Providers may also submit PRD Curves for any Price Responsive Demand that is not committed in accordance with the Reliability Assurance Agreement; provided that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue may only submit PRD Curves for the Real-time Energy Market. All PRD Curves shall be on a PRD Substation basis, and shall specify the maximum time period required to implement load reductions.

(b) Each Generating Market Buyer shall submit to the Office of the Interconnection: (i) hourly schedules for resource increments, including hydropower units, self-scheduled by the Market Buyer to meet its Equivalent Load; and (ii) the Dispatch Rate at which each such self-scheduled resource will disconnect or reduce output, or confirmation of the Market Buyer's intent not to reduce output.

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

scheduled bilateral transaction. Scheduling of bilateral transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

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

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

iii) In addition to the foregoing schedules for bilateral transactions, Market Participants shall submit confirmations of each scheduled bilateral transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(d) Market Sellers wishing to sell into the Day-ahead Energy Market shall submit offers for the supply of energy (including energy from hydropower units), demand reductions, Regulation, Operating Reserves or other services for the following Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Attachment DD of the PJM Tariff, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. *Any offer not designated as a Maximum Emergency Offer shall be considered available for scheduling and dispatch under both Emergency and non-Emergency conditions. Offers may only be designated as Maximum Emergency Offers to the extent that the Generation Capacity Resource falls into at least one of the following categories:*

i) Environmental limits. If the resource has a limit on its run hours imposed by a federal, state or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited to operating only during declared PJM capacity emergencies by a governmental authority.

ii) Fuel limits. If physical events beyond the control of the resource owner result in the temporary interruption of fuel supply and there is limited on-site fuel storage. A fuel supplier's exercise of a contractual right to interrupt supply or delivery under an interruptible service agreement shall not qualify as an event beyond the control of the resource owner.

iii) Temporary emergency conditions at the unit. If temporary emergency physical conditions at the resource significantly limit its availability.

iv) Temporary megawatt additions. If a resource can provide additional megawatts on a temporary basis by oil topping, boiler over-pressure, or similar techniques and such megawatts are not ordinarily otherwise available.

The submission of offers for resource increments that have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, and PJM Manuals, as applicable. Energy offered from generation resources that have not cleared a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region. The foregoing offers:

i) Shall specify the Generation Capacity Resource or Demand Resource and energy or demand reduction amount, respectively, for each hour in the offer period, and the minimum run time for generation resources and minimum down time for Demand Resources;

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

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

iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;

v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with a second schedule applicable if accepted after the foregoing deadline;

vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer, which offer shall remain open through the Operating Day for which the offer is submitted;

vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or

prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day; and

viii) Shall not exceed an energy offer price of $1,000/megawatt-*hour for all generation resources and Demand Resources that have cleared a Base Residual Auction or an Incremental Auction.*

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation that shall specify the megawatt of Regulation being offered, which must equal or exceed 0.1 megawatts, the Regulation Zone for which such regulation is offered, the price of the capability offer in dollars per MW~~h~~, the price of the performance offer in Dollars per change in MW, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the resource's opportunity costs. The ~~price of the offer~~ total of the performance offer multiplied by the historical average mileage used in the market clearing plus the capability offer shall not exceed $100 per MWh in the case of Regulation offered for all Regulation Zones. In addition to any market-based offer for Regulation, the Market Seller also shall submit a cost-based offer. A cost-based offer must be in the form specified in the PJM Manuals and consist of the following components as well as any other components specified in the PJM Manuals:

i. The costs (in $/MW) of the fuel cost increase due to the heat rate increase resulting from operating a unit at lower megawatt output incurred from the provision of Regulation;

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

iii. An adder of up to $12.00 per megawatt of Regulation provided applied to the capability offer.

Qualified Regulation capability must satisfy the measurement and verification tests specified in the PJM Manuals.

(f) Each Market Seller owning or controlling the output of a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative shall submit a forecast of the availability of each such Generation Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with start-up and no-load fees, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours.

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

(h) The Office of the Interconnection shall post the total hourly loads scheduled in the Day-ahead Energy Market, as well as, its estimate of the combined hourly load of the Market Buyers for the next four days, and peak load forecasts for an additional three days.

(i) Except for Economic Load Response Participants, all Market Participants may submit Increment Bids and/or Decrement Bids that apply to the Day-ahead Energy Market only. Such bids must comply with the requirements set forth in the PJM Manuals and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-ahead Energy Market. The Office of the Interconnection may require that a market participant shall not submit in excess of 3000 bid/offer segments in the Day-ahead Energy Market, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to 10:00 a.m. EPT on the day that the Day-ahead Energy Market will clear. For purposes of this provision, a bid/offer segment is each pairing of price and megawatt quantity submitted as part of an Increment Bid or Decrement Bid.

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

(k) An Economic Load Response Participant that wishes to participate in the Day-ahead Energy Market by reducing demand shall submit an offer to reduce demand to the Office of the Interconnection. The offer must equal or exceed 0.1 megawatts, and the offer shall specify: (i) the amount of the offered curtailment in minimum increments of .1 megawatts: (ii) the Day-ahead Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, start-up costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum of number of contiguous hours for which the load reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs).

(l) Market Sellers owning or controlling the output of a Demand Resource that was committed in an FRR Capacity Plan, self-supplied or offered and cleared in the Base Residual Auction or one of the Incremental Auctions, or owning or controlling the output of an ILR resource which was certified as specified in Attachment DD of the PJM Tariff, may submit demand reduction bids for the available load reduction capability of the Demand Resource or ILR resource. The submission of demand reduction bids for resource increments that have not cleared in the Base Residual Auction or in one of the Incremental Auctions, or for ILR resources that were not certified, or were not committed in an FRR Capacity Plan, shall be optional, but

any such bids must contain the information specified in the PJM Economic Load Response Program to be included in such bids. A Demand Resource that was committed in an FRR Capacity Plan, self-supplied or offered and cleared in a Base Residual Auction or an Incremental Auction may submit a demand reduction bid in the Day-ahead Energy Market as specified in the Economic Load Response Program, provided however, that in the event of an Emergency, PJM shall require Demand Resources and ILR resources to reduce load notwithstanding that the Zonal LMP at the time such Emergency is declared is below the price identified in the demand reduction bid.

(m) Market Sellers that wish to make Day-ahead Scheduling Reserves Resources available to sell Day-ahead Scheduling Reserves shall submit offers, each of which must equal or exceed 0.1 megawatts, in the Day-ahead Scheduling Reserves Market specifying: 1) the price of the offer in dollars per megawatt hour; and 2) such other information specified by the Office of the Interconnection as may be necessary to determine any relevant opportunity costs for the resource(s). The foregoing notwithstanding, to qualify to submit offers pursuant to this section, the Day-ahead Scheduling Reserves Resources shall submit energy offers in the Day-ahead Energy Market including start-up and shut-down costs for generation resource and Demand Resources, respectively, and all generation resources that are capable of providing Day-ahead Scheduling Reserves that a particular resource can provide that service. The MW quantity of Day-ahead Scheduling Reserves that a particular resource can provide in a given hour will be determined based on the energy ~~o~~Offer ~~d~~Data submitted in the Day-ahead Energy Market, as detailed in the PJM Manuals.

1.10.2 Pool-scheduled Resources.

Pool-scheduled resources are those resources for which Market Participants submitted offers to sell energy in the Day-ahead Energy Market and offers to reduce demand in the Day-ahead Energy Market, which the Office of the Interconnection scheduled in the Day-ahead Energy Market as well as generators committed by the Office of the Interconnection subsequent to the Day-ahead Energy Market. Such resources shall be committed to provide energy in the real-time dispatch unless the schedules for such units are revised pursuant to Sections 1.10.9 or 1.11. Pool-scheduled resources shall be governed by the following principles and procedures.

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, start-up, no-load and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in Section 1.10.1A.

(b) A resource that is scheduled by a Market Participant to support a bilateral sale, or that is self-scheduled by a Generating Market Buyer, shall not be selected by the Office of the Interconnection as a pool-scheduled resource except in an Emergency.

(c) Market Sellers offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the Office of the Interconnection that is sufficient to enable the Office of the Interconnection to determine the available operating hours of such facilities.

(d) The Market Seller of a resource selected as a pool-scheduled resource shall receive payments or credits for energy, demand reductions or related services, or for start-up and no-load fees, from the Office of the Interconnection on behalf of the Market Buyers in accordance with Section 3 of this Schedule 1. Alternatively, the Market Seller shall receive, in lieu of start-up and no-load fees, its actual costs incurred, if any, up to a cap of the resource's start-up cost, if the Office of the Interconnection cancels its selection of the resource as a pool-scheduled resource and so notifies the Market Seller before the resource is synchronized.

(e) Market Participants shall make available their pool-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone.

(f) Economic Load Response Participants offering to reduce demand shall specify: (i) the amount of the offered curtailment, which offer must equal or exceed 0.1 megawatts, in minimum increments of .1 megawatts; (ii) the real-time Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, shut-down costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum number of contiguous hours for which the load reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Real-time Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs). Economic Load Response Participants offering to reduce demand shall also indicate the hours that the demand reduction is not available.

1.10.3 Self-scheduled Resources.

Self-scheduled resources shall be governed by the following principles and procedures.

(a) Each Generating Market Buyer shall use all reasonable efforts, consistent with Good Utility Practice, not to self-schedule resources in excess of its Equivalent Load.

(b) The offered prices of resources that are self-scheduled, or otherwise not following the dispatch orders of the Office of the Interconnection, shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.

(c) Market Participants shall make available their self-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone, by submitting an offer as to such resources.

(d) A Market Participant self-scheduling a resource in the Day-ahead Energy Market that does not deliver the energy in the Real-time Energy Market, shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

1.10.4 Capacity Resources.

(a) A Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that is selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection. Such a Generation Capacity Resource that does not deliver energy as scheduled shall be deemed to have experienced a Generator Forced Outage to the extent of such energy not delivered. A Market Participant offering such Generation Capacity Resource in the Day-ahead Energy Market shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Energy from a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that has not been scheduled in the Day-ahead Energy Market may be sold on a bilateral basis by the Market Seller, may be self-scheduled, or may be offered for dispatch during the Operating Day in accordance with the procedures specified in this Schedule. Such a Generation Capacity Resource that has not been scheduled in the Day-ahead Energy Market and that has been sold on a bilateral basis must be made available upon request to the Office of the Interconnection for scheduling and dispatch during the Operating Day if the Office of the Interconnection declares a Maximum Generation Emergency. Any such resource so scheduled and dispatched shall receive the applicable Real-time Price for energy delivered.

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

1.10.5 External Resources.

(a) External Resources may submit offers to the PJM Interchange Energy Market, in accordance with the day-ahead and real-time scheduling processes specified above. An External Resource selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection, and except as specified below shall be compensated on the same basis as other pool-scheduled resources. External Resources that are not capable of dynamic dispatch shall, if selected by the Office of the Interconnection on the basis of the Market Seller's Offer Data, be block loaded on an hourly scheduled basis. Market Sellers shall offer External Resources to the PJM Interchange Energy Market on either a resource-specific or an aggregated resource basis. A Market Participant whose pool-scheduled resource does not deliver the energy scheduled in the Day-ahead Energy Market shall replace such energy not delivered as scheduled in the Day-ahead Energy Market with energy from the PJM Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Offers for External Resources from an aggregation of two or more generating units shall so indicate, and shall specify, in accordance with the Offer Data requirements specified by the Office of the Interconnection: (i) energy prices; (ii) hours of energy availability; (iii) a minimum dispatch level; (iv) a maximum dispatch level; and (v) unless such information has previously been made available to the Office of the Interconnection, sufficient information, as specified in the PJM Manuals, to enable the Office of the Interconnection to model the flow into the PJM Region of any energy from the External Resources scheduled in accordance with the Offer Data.

(c) Offers for External Resources on a resource-specific basis shall specify the resource being offered, along with the information specified in the Offer Data as applicable.

1.10.6 External Market Buyers.

(a) Deliveries to an External Market Buyer not subject to dynamic dispatch by the Office of the Interconnection shall be delivered on a block loaded basis to the bus or buses at the electrical boundaries of the PJM Region, or in such area with respect to an External Market Buyer's load within such area not served by Network Service, at which the energy is delivered to or for the External Market Buyer. External Market Buyers shall be charged (which charge may be positive or negative) at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing bus or buses.

(b) An External Market Buyer's hourly schedules for energy purchased from the PJM Interchange Energy Market shall conform to the ramping and other applicable requirements of the interconnection agreement between the PJM Region and the Control Area to which, whether as an intermediate or final point of delivery, the purchased energy will initially be delivered.

(c) The Office of the Interconnection shall curtail deliveries to an External Market Buyer if necessary to maintain appropriate reserve levels for a Control Zone as defined in the PJM Manuals, or to avoid shedding load in such Control Zone.

1.10.6A Transmission Loading Relief Customers.

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

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

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

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

(c) In order to make elections under this Section 1.10.6A, an entity must (i) have met the creditworthiness standards established by the Office of the Interconnection or provided a letter of

credit or other form of security acceptable to the Office of the Interconnection, and (ii) have executed either the Agreement, a Service Agreement under the PJM Tariff, or other agreement committing to pay all Transmission Congestion Charges incurred under this Section.

1.10.7 Bilateral Transactions.

Bilateral transactions as to which the parties have notified the Office of the Interconnection by the deadline specified in Section 1.10.1A that they elect not to be included in the Day-ahead Energy Market and that they are not willing to incur Transmission Congestion Charges in the Real-time Energy Market shall be curtailed by the Office of the Interconnection as necessary to reduce or alleviate transmission congestion. Bilateral transactions that were not included in the Day-ahead Energy Market and that are willing to incur congestion charges and bilateral transactions that were accepted in the Day-ahead Energy Market shall continue to be implemented during periods of congestion, except as may be necessary to respond to Emergencies.

1.10.8 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers and PRD Curves properly submitted by Load Serving Entities for the Price Responsive Demand loads they serve; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv) the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) Not earlier than 4:00 p.m. of the day before each Operating Day, or such other deadline as may be specified by the Office of the Interconnection in the PJM Manuals, the Office of the Interconnection shall: (i) post the aggregate Day-ahead Energy Market results; (ii) post the Day-

ahead Prices; and (iii) inform the Market Sellers, Market Buyers, and Economic Load Response Participants of their scheduled injections, withdrawals, and demand reductions respectively.

(c) Following posting of the information specified in Section 1.10.8(b), the Office of the Interconnection shall revise its schedule of generation resources to reflect updated projections of load, conditions affecting electric system operations in the PJM Region, the availability of and constraints on limited energy and other resources, transmission constraints, and other relevant factors.

(d) Market Buyers shall pay PJMSettlement and Market Sellers shall be paid by PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the offer that set the Day-ahead Price is positive. Market Buyers shall be paid by PJMSettlement and Market Sellers shall pay PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the offer that set the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Section 3.3A of this Schedule.

(e) If the Office of the Interconnection discovers an error in prices and/or cleared quantities in the Day-ahead Energy Market, Real-time Energy Market, Ancillary Services Markets or Day Ahead Scheduling Reserve Market after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 12:00 p.m. of the second business day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the second business day following the initial publication of the results for the Day-ahead Scheduling Reserve Market and Day-ahead Energy Market. After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the fifth business day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the fifth business day following the initial publication of the results in the Day-ahead Scheduling Reserve Market and the Day-ahead Energy Market. Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating Day for the Ancillary Services Markets, Day-ahead Energy Market and Real-time Energy Market, and no later than 5:00 p.m. of the tenth calendar day following the initial publication of the results in the Day-ahead Scheduling Reserve Market. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced market results are under publicly noticed review by the FERC.

(f) Consistent with Section 18.17.1 of the PJM Operating Agreement, and notwithstanding anything to the contrary in the Operating Agreement or in the PJM Tariff, to allow the tracking of Market Participants' non-aggregated bids and offers over time as required by FERC Order No. 719, the Office of the Interconnection shall post on its Web site the non-aggregated bid data and Offer Data submitted by Market Participants (for participation in the PJM Interchange Energy

Market) approximately four months after the bid or offer was submitted to the Office of the Interconnection.

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, a generation rebidding period shall exist from 4:00 p.m. to 6:00 p.m. on the day before each Operating Day. During the rebidding period, Market Participants may submit revisions to generation Offer Data for any generation resource that was not selected as a pool-scheduled resource in the Day-ahead Energy Market. Adjustments to Day-ahead Energy Markets shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy ~~m~~Market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 60 minutes prior to the hour in which the adjustment is to take effect, as follows:

i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;

ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or

iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or

iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any start-up fee.

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

(d) An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase in the Day-ahead Energy Market by notifying the Office of the Interconnection of the adjustment in deliveries not later than 60 minutes prior to the hour in which the adjustment is

to take effect, but any such adjustment shall not affect the obligation of the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(e) For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section 1.10, the Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules for the hour.

1.11 Dispatch.

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

1.11.1 Resource Output.

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

1.11.2 Operating Basis.

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

1.11.3 Pool-dispatched Resources.

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

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

1.11.3A Maximum Generation Emergency.

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

1.11.4 Regulation.

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

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

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

1.11.4A Synchronized Reserve.

(a) A Market Buyer may satisfy its Synchronized Reserve Obligation from its own generation resources and/or Demand Resources capable of providing Synchronized Reserve, by contractual arrangements with other Market Participants able to provide Synchronized Reserve,

or by purchases from the PJM Synchronized Reserve Market at the rates set forth in Section 3.2.3A. PJMSettlement shall be the Counterparty to the purchases and sales of Synchronized Reserve in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Synchronized Reserve Obligation.

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

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

1.11.4B Non-Synchronized Reserve.

(a) A Market Buyer may satisfy its Non-Synchronized Reserve Obligation from its own generation resources and/or Demand Resources capable of providing Non-Synchronized Reserve, by contractual arrangements with other Market Participants able to provide Non-Synchronized Reserve, or by purchases from the PJM Non-Synchronized Reserve Market at the rates set forth in Section 3.2.3A.001.

(b) The Office of the Interconnection shall obtain Non-Synchronized Reserve from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Demand Resources as needed to ensure the Primary Reserve requirement of each Reserve Zone of the PJM Region not otherwise satisfied by the Market Buyers. Resources offering to sell Non-Synchronized Reserve shall be selected to provide Non-Synchronized Reserve on the basis of each generation resource's and/or Demand Resource's estimated unit specific opportunity cost of the resource providing Non-Synchronized Reserve, and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Synchronized Reserve and other ancillary services. Estimated unit specific opportunity costs for generation resources shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the ~~absolute value of~~ the difference between the Locational marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Non-Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources will be zero.

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

1.11.5 PJM Open Access Same-time Information System.

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

2.2 General.

The Office of the Interconnection shall determine the least cost security-constrained dispatch, which is the least costly means of serving load *and meeting reserve requirements* at different locations in the PJM Region based on actual operating conditions existing on the power grid (including transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6) and on the prices at which Market Sellers have offered to supply energy and offers by Economic Load Response Participants to reduce demand that qualify to set Locational Marginal Prices in the PJM Interchange Energy Market. Locational Marginal Prices for the generation and load busses in the PJM Region, including interconnections with other Control Areas, will be calculated based on the actual economic dispatch and the prices of energy and demand reduction offers. The process for the determination of Locational Marginal Prices shall be as follows:

(a) To determine actual operating conditions on the power grid in the PJM Region, the Office of the Interconnection shall use a computer model of the interconnected grid that uses available metered inputs regarding generator output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network. The computer model employed for this purpose, referred to as the State Estimator program, is a standard industry tool and is described in Section 2.3 below. It will be used to obtain information regarding the output of generation supplying energy to the PJM Region, loads at busses in the PJM Region, transmission losses, and power flows on binding transmission constraints for use in the calculation of Locational Marginal Prices. Additional information used in the calculation, including Dispatch Rates and real time schedules for external transactions between PJM and other Control Areas and dispatch and pricing information from entities with whom PJM has executed a joint operating agreement, will be obtained from the Office of the Interconnection's dispatchers.

(b) Using the prices at which energy is offered by Market Sellers and demand reductions are offered by Economic Load Response Participants to the PJM Interchange Energy Market, the Office of the Interconnection shall determine the offers of energy and demand reductions that will be considered in the calculation of Locational Marginal Prices. As described in Section 2.4 below, every qualified offer for demand reduction and of energy by a Market Seller from resources that are ~~*following economic dispatch instructions of*~~*dispatched by* the Office of the Interconnection will be utilized in the calculation of Locational Marginal Prices, including, without limitation, qualified offers from Economic Load Response Participants in either the Day-Ahead or Real-Time Energy Markets that satisfy the Net Benefits Test. Offers of ~~*demand reduction*~~*economic load response* from Demand Resources in the Real-time Energy Market will not be eligible to set Locational Marginal Prices, unless metered directly by the Office of the Interconnection. *Offers of Full Program Option resources in the Emergency Load Response Program are eligible to set real time Locational Marginal Prices when the Office of the Interconnection has implemented Emergency procedures and such resources are required to reduce demand in the PJM Region, so long as sufficient data is available to accurately model the resources.*

(c) Based on the system conditions on the PJM power grid, determined as described in (a), and the eligible energy and demand reduction offers, determined as described in (b), the Office of the Interconnection shall determine the least costly means of obtaining energy to serve the next increment of load at each bus in the PJM Region, in the manner described in Section 2.5 below. The result of that calculation shall be a set of Locational Marginal Prices based on the system conditions at the time.

2.3 Determination of System Conditions Using the State Estimator.

Power system operations, including, but not limited to, the determination of the least costly means of serving load *and meeting reserve requirements*, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In calculating Locational Marginal Prices, the Office of the Interconnection shall obtain a complete and consistent description of conditions on the electric network in the PJM Region by using the most recent power flow solution produced by the State Estimator *program and utilized in the PJM dispatch algorithm*, which *State Estimator program* is also used by the Office of the Interconnection for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available real-time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at busses for which real-time information is unavailable. The Office of the Interconnection shall obtain a State Estimator solution every five minutes, which shall provide the megawatt output of generators and the loads at busses in the PJM Region, transmission line losses, and actual flows or loadings on constrained transmission facilities. External transactions between PJM and other Control Areas shall be included in the Locational Marginal Price calculation on the basis of the real time transaction schedules implemented by the Office of the Interconnection's dispatcher.

2.4 Determination of Energy Offers Used in Calculating Real-time Prices.

(a) During the Operating Day, real-time Locational Marginal Prices derived in accordance with this Section shall be determined every five minutes and integrated hourly values of such determinations shall be the basis of sales and purchases of energy in the Real-time Energy Market and of Transmission Congestion Charges under the PJM Tariff not covered by the Day-ahead Energy Market.

(b) To determine the energy offers submitted to the PJM Interchange Energy Market that shall be used during the Operating Day to calculate the Real-time Prices, the Office of the Interconnection shall determine *the applicable marginal energy offer of the* ~~which~~ resources *being dispatched by the Office of the Interconnection* ~~are following its economic dispatch instructions~~. A resource ~~will be considered to be following economic dispatch instructions and~~ shall be included in the calculation of Real-time Prices if ~~:~~

~~*i)* the~~ the applicable *marginal energy offer of the* ~~price bid by a Market Seller for energy from the~~ resource *being dispatched by the Office of the Interconnection* is less than or equal to the Dispatch Rate for the area of the PJM Region in which the resource is located~~.; or~~

~~ii) the resource is specifically requested to operate by the Office of the Interconnection's dispatcher.~~

(c) In determining whether a resource satisfies the condition described in (b), the Office of the Interconnection will determine the ~~*bid price associated with an*~~ *applicable marginal* energy offer by comparing the ~~*actual*~~ *requested* megawatt output of the resource with the Market Seller's offer price curve. ~~*Because of practical generator response limitations, a resource whose megawatt output is not ten percent more than the megawatt level specified on the offer price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but t*~~T*he *applicable marginal* energy ~~*price*~~ offer used in the calculation of Real-time Prices shall not exceed the applicable Dispatch Rate. Units that must be run for local area protection shall not be considered in the calculation of Real-time Prices.

2.5 Calculation of Real-time Prices.

(a) The Office of the Interconnection shall determine the least costly means of obtaining energy to serve the next increment of load (taking account of any applicable and available load reductions indicated on PRD Curves properly submitted by any PRD Provider) at each bus in the PJM Region represented in the State Estimator and each Interface Pricing Point between PJM and an adjacent Control Area, based on the system conditions described by the most recent power flow solution produced by the State Estimator program *and utilized in the PJM dispatch algorithm* and the energy offers that are the basis for the Day-ahead Energy Market, or that are determined to be eligible for consideration under Section 2.4 in connection with the real-time dispatch, as applicable. This calculation shall be made by applying ~~an incremental linear optimization method to minimize energy costs~~ *a real-time joint optimization of energy and reserves*, given actual system conditions, a set of energy offers, *a set of reserve offers, a set of Reserve Penalty Factors,* and any binding transmission constraints that may exist. In performing this calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a generation resource or decrease an increment of energy being consumed by a Demand Resource, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses. *The real-time Locational Marginal Prices at a bus shall be determined through the joint optimization based on the lowest marginal cost to serve the next increment of load at the bus taking into account the applicable reserve requirements, unit resource constraints, transmission constraints and marginal loss impact.* ~~*The energy offer or offers that can serve an increment of load at a bus at the lowest cost, calculated in this manner, shall determine the Real-time Price at that bus.*~~

(*b*) *If all reserve requirements in every modeled Reserve Zone can be met at prices less than or equal to the Reserve Penalty Factors for both the Synchronized Reserves and Non-synchronized Reserves, real-time Locational Marginal Prices shall be calculated as described in Section 2.5(a) above and no Reserve Penalty Factor shall apply beyond the normal lost opportunity costs incurred by the reserve requirements. When a reserve requirement cannot be met at a price less than or equal to the Reserve Penalty Factors associated with a Reserve Zone, the real-time Locational Marginal Prices shall be calculated by incorporating the applicable Reserve Penalty Factor for the deficient reserve product as the lost opportunity cost impact of the deficient reserve requirement, and the components of Locational Marginal Prices referenced in Section 2.5(a) above shall be calculated accordingly.*

(c) If the Office of the Interconnection has initiated in a Reserve Zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in

the PJM Manuals, Locational Marginal Prices for that Reserve Zone will be calculated including the Reserve Penalty Factors of all reserve products in that Reserve Zone.

(~~b~~*d*) During the Operating Day, the calculation set forth in (a) shall be performed every five minutes, using the Office of the Interconnection's Locational Marginal Price program, producing a set of Real-time Prices based on system conditions during the preceding interval. The prices produced at five-minute intervals during an hour will be integrated to determine the Real-time Prices for that hour.

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 ~~at~~: (i) the capability Regulation market-clearing price determined in accordance with subsection (~~eg~~) of this section; ~~, plus~~ the amounts, if any, described in subsection (~~fe~~) of this section; and (iii) the Internal Market Buyer's pro rata share of any performance credits paid to regulating resources calculated in accordance with subsection (f) of this section.

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

(c) The 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 (f) 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 ~~*The 5-minute clearing prices are calculated as the* highest sum of a resource's Regulation offer plus its *estimated*~~ unit-specific opportunity costs, *during the 5-minute period* determined as described in subsection (d) below from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.3.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation *5-minute* ~~market~~ clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour shall be equal to ~~*the sum of the unit-specific opportunity costs (i) incurred during the hour in which the obligation is fulfilled, plus costs (ii) associated with uneconomic operation during the hour preceding the initial regulating hour ("preceding*~~

~~*shoulder hour"), plus costs (iii) associated with uneconomic operation during the hour after the final regulating hour ("following shoulder hour").*~~

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

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

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

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

~~(e) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's Regulation signals from the generation resource's expected output level if it had been dispatched~~

~~in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.~~

~~The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.~~

~~The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the following shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the following shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the following shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.~~

(~~f~~e) 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.

(f) 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 (f) 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 capacity Regulation market-clearing price.

(g) 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.

(h) 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.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to section 1.10.1A(e) of this Schedule. A Regulation supplier fails the three-pivotal supplier test in any hour in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

(b) For the purposes of conducting the three-pivotal supplier test pursuant to this section, the following applies:

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region for which the 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.

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 unfor*e*seen Operating Reserve requirements that are not reflected in the Day-ahead Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load fees and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve

credits, identified as RA Credits for Reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

(c) The sum of the foregoing credits calculated in accordance with Section 3.2.3(b) plus any unallocated charges from Section 3.2.3(h) and 5.1.7~~,~~ and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program shall be the cost of Operating Reserves in the Day-ahead Energy Market.

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following segments: 1) the greater of their day-ahead schedules or minimum run time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or minimum run time (minimum down time for Demand Resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time (minimum down time for Demand Resources) and Segment 2 will include the remainder of the contiguous hours when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

Credits received pursuant to this section shall be equal to the positive difference between a resource's total offered price for start-up (shutdown costs for Demand Resources) and no-load fees and energy, determined on the basis of the resource's scheduled output, and the total value of the resource's energy as determined by the Real-time Energy Market and the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for segment 2 shall exclude start up (shutdown costs for Demand Resources) costs for generation resources.

Except as provided in Section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to Section 3.2.3(b) plus the resource's opportunity cost and less any amounts credited for Synchronized Reserve in excess of the Synchronized Reserve offer plus the resource's opportunity cost and less any amounts credited for providing Reactive Services as specified in Section 3.2.3B, and less any amounts for Day-ahead Scheduling Reserve in excess of the Day-ahead Scheduling Reserve offer plus the resource's opportunity cost, shall be credited to the Market Seller.

Synchronized Reserve, *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 {(LMPDMW - AG) x (URTLMP – UB)}, where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

AG equals the actual hourly integrated output of the unit;

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

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

where URTLMP - UB shall not be negative.

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

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described above for a steam unit or combined cycle unit operating in combined cycle mode.

(ii) if the unit is scheduled to produce energy in the day-ahead market, but the unit is not called on by PJM and does not operate in real time, then the

Market Seller shall be credited hourly in an amount equal to the higher of (i) {(URTLMP – UDALMP) x DAG}, or (ii) {(URTLMP – UB) x DAG} where:

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

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

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

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

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

(f-2) A Market Seller's hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves, plus any redispatch costs incurred in accordance with section 10(a) of this Schedule, shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (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.

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 busses that define all interfaces or all hubs are located in the region. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by busses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed in accordance with the following provisions:

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of an Operating Reserve shortage in real-time or where PJM initiates the request for load reductions in real-time in order to avoid an Operating

Reserve shortage ~~as described in this Schedule, Section 6A, Scarcity Pricing~~.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in Section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for the PJM Region.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside the PJM Region pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared ("Maximum Generation Emergency Alert"); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the Operating Reserves credit otherwise provided by Section 3.2.3.(b) or Section 3.2.3(e) in connection with market~~d~~-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 ~~o~~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 <= 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

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

$$RL_Desired_t = AOutput_{t-1} + \left(Ramp_Request_t * Case_Eff_time_{t-1} \right)$$

where:

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

To determine if a 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 <= 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 n 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 to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve charges shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve charges shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve

charges shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region. For the purposes of this section, the Western Region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, *DEOK* transmission Zones, and the Eastern Region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones. The regional balancing Operating Reserve rates shall be determined in accordance with the following provisions:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-

time deviations, respectively. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

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

(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.

3.2.3A Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each ~~*Synchronized*~~ Reserve Zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such ~~*Synchronized*~~ Reserve Zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). An Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts if any, described in subsections (g), (h) and (i) of this section.

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

i) Credits for Synchronized Reserve provided by generation ~~*units*~~ *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; with the exception of those hours in which the Non-Synchronized Reserve Market Clearing Price for the applicable Reserve 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 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 ~~Synchronized~~ Reserve Zone by the Office of the Interconnection ~~*prior to the operating hour and such market-clearing price shall be equal to, from among the generation resources or Demand Resources selected to provide Synchronized Reserve for such Synchronized Reserve Zone, the highest sum of either (i) a generation resource's Synchronized Reserve offer and opportunity cost or (ii) a demand response resource's Synchronized Reserve offer*~~*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, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve requirement in a Reserve 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, but less than or equal to the sum of the Synchronized Reserve Penalty Factor and the Primary Reserve Penalty Factor for the Reserve Zone. If the Office of the Interconnection has initiated in a Reserve 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.*

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

i. $250/MWh for the 2011/2012 Delivery Year;

ii. $400/MWh for the 2012/2013 Delivery Year;

iii. $550/MWh for the 2013/2014 Delivery Year; and

iv. $850/MWh as of the 2014/2015 Delivery Year.

After June 1, 2014, 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 the Delivery Year(s).

(e) In determining the 5-minute Synchronized Reserve ~~Market Clearing~~ clearing ~~Price~~price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the expected Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

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

Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

(g) Charges for Tier 1 Synchronized Reserve will be allocated in proportion to the amount of Tier 1 Synchronized Reserve applied to each Synchronized Reserve Obligation. In the event Tier 1 Synchronized Reserve is provided by a Market Seller in excess of that Market Seller's Synchronized Reserve Obligation, the remainder of the Tier 1 Synchronized Reserve that is not utilized to fulfill the Seller's obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

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

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

(j) In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled by the owner to provide Tier 2 Synchronized Reserve fails to provide the assigned or self-scheduled amount of Synchronized Reserve in response to an actual Synchronized Reserve Event, , *the 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 ~~*Synchronized*~~ Reserve Zone of the PJM Region on which the Synchronized Reserve Obligations, except for the additional obligations set forth in this section, are based shall be reduced by the amount of this shortfall for the applicable three-day period.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l) is the difference between the generation resource's output or the Demand Resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a

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

(l) The magnitude of response by a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load Demand Resource's consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity 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 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 for the hour ("Non-Synchronized Reserve Obligation"). 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 (d) of this section, plus the amounts if any, described in paragraphs (g), (h) and (i) 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 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. Opportunity costs for Demand Resources to provide Non-Synchronized Reserves are zero.*

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve 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 serving the next increment of demand for Non- Synchronized Reserve in each Reserve Zone inclusive of opportunity costs associated with meeting the Primary Reserve requirement. When the Primary Reserve requirement in a Reserve 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 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.

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

i. $250/MWh for the 2011/2012 Delivery Year;

ii. $400/MWh for the 2012/2013 Delivery Year;

iii. $550/MWh for the 2013/2014 Delivery Year; and

iv. $850/MWh as of the 2014/2015 Delivery Year.

After June 1, 2014, 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 solely for the purpose of providing Non-Synchronized Reserves shall be equal to the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Non-Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) ~~the absolute value of~~ the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. The opportunity costs for a Demand Resource shall be zero.

(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 absolute value of~~ the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the

generation resource) in the PJM Interchange Energy Market. The opportunity costs for a Demand Resource shall be zero.

(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 or a Demand Resource, except for Batch Load Demand Resources covered by Section 3.2.3A(1), 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.

(h) 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 Non-Synchronized Reserve fails to provide the assigned or self-scheduled 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.
(i) 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 megawattts in its offer at the start of a Non-Synchronized Reserve Event shall be the difference between (i) the Batch Load Demand Resource's consumption at the end of the Non-Synchronized Reserve Event and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the end of the Non-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 Non-Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.

3.2.3A.01 Day-ahead Scheduling Reserves.

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

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

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

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

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

(iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest

consumption between one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

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

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

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

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit hourly in an amount equal to {(LMPDMW - AG) x (URTLMP - UB)}

where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

AG equals the actual hourly integrated output of the unit;

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

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

where URTLMP - UB shall not be negative.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in

Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

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

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

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

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

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

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

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to Section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit hourly in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual hourly integrated output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any ~~r~~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 generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generation unit's bus, (C) the generation unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations

of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

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

3.2.5 Transmission Loss Charges.

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

3.2.6 Emergency Energy.

(a) *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~~b~~) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each hour of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(d~~c~~) The net costs or net revenues associated with sales or purchases of hourly energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each hour of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its

net PJM Interchange in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Buyer in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market Buyer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Buyer's internal accounting.

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

3.3 Market Sellers.

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

3.3.1 Spot Market Energy Charges.

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

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

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

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

3.3.2 Regulation.

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

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

3.3.3 Operating Reserves.

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

3.3.4 Emergency Energy.

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

3.3.5 Synchronized Reserve.

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

3.*3.5A Non-Synchronized Reserve.*

Each Market Seller that is also an Internal Market Buyer shall have an hourly Non-Synchronized Reserve objective and shall be credited or charged in connection therewith as specified in Section 3.2.3A.001(a). All other Market Sellers supplying Non-Synchronized Reserve at the direction of the Office of the Interconnection shall be credited for each increment of such Synchronized Reserve at the price specified in Section 3.2.3A.001(b), as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

3.3.6 Billing.

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

6A ~~**Scarcity Pricing.**~~ **[Reserved For Future Use]**

6A.1 ~~Scarcity Conditions.~~ [Reserved **F**or Future Use]

~~6A.1.1 Commencement of Scarcity Conditions.~~

~~Scarcity conditions that trigger scarcity pricing will occur when the Office of the Interconnection's system operators perform any one of the following identifiable, specifically defined actions for a Scarcity Pricing Region:~~

~~a) Begin to dispatch online generators, which are partially designated as Maximum Emergency, into emergency output levels.~~

~~b) Begin to dispatch online generators, which are designated entirely as Maximum Emergency, above their designated minimum load points, if they are currently online and operating at their minimum load points because of restrictive operating parameters associated with the generators.~~

~~c) Begin to dispatch any offline generators that are designated entirely as Maximum Emergency and that have start times plus notification times less than or equal to 30 minutes.~~

~~d) Voltage reduction action as described in the PJM Manuals.~~

~~e) Emergency energy purchases pursuant to section 1.6.2(vi) of this Schedule.~~

~~f) Manual load dump action as described in the PJM Manuals.~~

~~Whenever the Office of the Interconnection's system operators take any of the above designated actions triggering scarcity pricing, they shall post on the PJM website the emergency message describing the action and include in the posting the Scarcity Pricing Region for which the action is being taken.~~

~~6A.1.2 Termination of Scarcity Conditions.~~

~~Scarcity pricing will be terminated in a Scarcity Pricing Region when demand and reserves can be fully satisfied with generation that is not designated Maximum Emergency. Under this condition, some generation that is designated Maximum Emergency may continue to operate due to timing limitations or operating limitations, but that generation is no longer needed under dispatch to satisfy system requirements, and scarcity pricing will no longer apply. Under no circumstances shall scarcity conditions be terminated if any of the following conditions remain in effect for the Scarcity Pricing Region:~~

~~a) Voltage reduction action as described in the PJM Manuals.~~

~~b) Emergency energy purchases from offers that do not have minimum purchase requirements of greater than 30 minutes duration attached to the offer.~~

~~c) Manual load dump action as described in the PJM Manuals.~~

~~The Office of the Interconnection shall post on the PJM website the time when scarcity conditions are terminated.~~

~~6A.1.3 Maximum Emergency Offer Limitations.~~

~~For purposes of defining scarcity conditions, the Office of the Interconnection shall consider units that have been classified as Maximum Emergency only if they fall in one of the following categories:~~

~~a) Environmental limits. If the unit has a hard cap on its run hours imposed by an environmental regulator that will temporarily significantly limit its availability.~~

~~b) Fuel limits. If physical events beyond the control of the unit owner result in the temporary interruption of fuel supply and there is limited on-site fuel storage. A fuel supplier's exercise of a contractual right to interrupt supply or delivery under an interruptible service agreement shall not qualify as an event beyond the control of the unit owner.~~

~~c) Temporary emergency conditions at the unit. If temporary emergency physical conditions at the unit significantly limit its availability.~~

~~d) Temporary megawatt additions. If a unit can provide additional megawatts on a temporary basis by oil topping, boiler over-pressure, or similar techniques and such megawatts are not ordinarily otherwise available.~~

~~The Office of the Interconnection shall post on its website the aggregate amount of generation megawatts that are classified as Maximum Emergency.~~

6A.2 ~~Scarcity Pricing Regions.~~ [Reserved For Future Use]

~~6A.2.1 Established Scarcity Pricing Regions.~~

~~There shall be the following Scarcity Pricing Regions: (1) Entire Market Region consisting of all transmission zones in the PJM market; (2) Bedington-Black Oak Region consisting of all pricing nodes that have a 5% or greater positive power distribution factor ("dfax") relative to the Bedington-Black Oak constraint; (3) the Eastern MAAC Region consisting of all pricing nodes that have a 5% or greater dfax relative to the Eastern Reactive Transfer constraint, (4) Eastern Market Region consisting of all pricing nodes that have a 5% or greater positive dfax relative to the Bedington-Black Oak and the Central Reactive Transfer constraints; (5) the MAAC Region, consisting of all pricing nodes that have a 5% or greater positive dfax relative to the Western Reactive Transfer constraint; and (6) the AP South Region, consisting of all pricing nodes that have a 5% or greater positive dfax relative to the AP South Reactive Transfer constraint.~~

~~6A.2.2 Annual Review of Scarcity Pricing Regions.~~

~~On an annual basis, PJM will review the defined Scarcity Pricing Regions and file changes (additions or deletions) to them with the Commission, as required. Additional Scarcity Pricing Regions must meet the following criteria: (1) consist of at least two entire transmission zones; (2) consist of contiguous transmission zones and sub-zones; (3) transmission import or transfer must be limited by EHV (500 kV or greater) constraints; and (4) consist of pricing nodes that have a 5% or greater positive dfax relative to the constraints.~~

~~6A.2.3 Additional Temporary Scarcity Pricing Regions.~~

~~Additional temporary Scarcity Pricing Regions shall be designated by the Office of the Interconnection during the year when warranted by a non-transitory change in the topology of the transmission system. Additional temporary Scarcity Pricing Regions must meet the criteria set forth in section 6A.2.2. The Office of the Interconnection shall designate and post on the PJM website an additional temporary Scarcity Pricing Region within 72 hours of operational conditions warranting the additional temporary Scarcity Pricing Region. The temporary Scarcity Pricing Region shall become effective on the day following such posting, provided that the posting is before noon. If and when the topology is restored to its prior state or the change otherwise no longer warrants the designation of a temporary Scarcity Pricing Region, the Office of the Interconnection shall make a posting ending the additional designation. The termination of the temporary Scarcity Pricing Region shall become effective on the day following the posting, provided that the posting is before noon.~~

6A.3 ~~Scarcity Pricing.~~ [Reserved For Future Use]

~~When scarcity conditions exist in a Scarcity Pricing Region, the region is considered incapable of meeting demand under normal economic dispatch conditions. Under such scarcity conditions, the Locational Marginal Prices of all nodes in a Scarcity Pricing Region will be determined based on the highest market-based offer price of all generating units operating under the Office of the Interconnection's direction to supply either energy or reserves on a real-time dispatch basis. No offer capping under section 6.4 of this Schedule may be initiated or continued in the Scarcity Pricing Region while scarcity pricing is in effect; provided, however, that generation in the Scarcity Pricing Region shall remain subject to the overall offer cap of $1000 per megawatt-hour. During the period that scarcity pricing is in effect, the Office of the Interconnection's system operators may direct generating units in the Scarcity Pricing Region to reduce from their maximum output for system or local transmission control. In such event, such reductions shall be treated as reductions for reliability under which the generation supplier shall be entitled to opportunity cost compensation equal to the megawatt-hour reduction times the difference between the Locational Marginal Price at the generator bus and the generation supplier's offer price consistent with section 3.2.3(f) of this Schedule. In addition, if a generator outside of a Scarcity Pricing Region is called upon to relieve the transmission constraint that caused the scarcity pricing condition in a Scarcity Pricing Region, then during the time that scarcity pricing is in effect in that Scarcity Pricing Region, that generation supplier shall be paid the higher of the generation-weighted Locational Marginal Price within the region determined as explained above or the price it otherwise would have been paid under this Schedule; however, that generation supplier's offer shall not be used to set Locational Marginal Prices in the Scarcity Pricing Region.~~

Emergency Operations

PJM will initiate the request for load reduction following the declaration of Maximum Emergency Generation and prior to the implementation of Load Management Steps 1 and 2. (Implementation of the Emergency Load Response Program can be used for regional emergencies.) It is implemented whenever generation is needed that is greater than the highest economic incremental cost. PJM posts the request for load reduction on the PJM website, on the Emergency Conditions page, and on eData, and issues a burst email to the Emergency Load Response majordomo. A separate All-Call message is also issued.

Following PJM's request to reduce load, (i) participants in the Energy Only Option voluntarily may reduce load; and (ii) participants in the Full Program Option are required to reduce load unless they already have reduced load pursuant to the Economic Load Response Program. PJM will dispatch the resources of all Emergency Load Response Program participants (not already dispatched under the Economic Load Response Program) based on the Minimum Dispatch Prices specified in the participants' Emergency Registration Forms.

The Minimum Dispatch Price *and all offers* of ~~*a*~~ Full Program Option ~~*participant*~~ *resources and Energy Only Option resources in the Emergency Load Response Program are eligible to* ~~*that reduces load may*~~ set the real time Locational ~~m~~Marginal Prices ("LMP") *when the Office of the Interconnection has implemented Emergency procedures and* ~~*provided that the*~~ *such resources* ~~*participant's load reductions*~~ *are* ~~*needed*~~ *required* to ~~*meet*~~ *reduce* demand in the PJM Region, *so long as sufficient data is available to accurately model the resources.* ~~*The Minimum Dispatch Price of an Energy Only Option participant that reduces load may set the real time LMP provided that such participant's load reductions are needed to meet demand in the PJM Regions and the*~~ Energy Only Option ~~*participant's*~~ resources *must also* satisf*y*~~*ies*~~ PJM's telemetry requirements.

Participants in the Emergency Load Response Program must provide real-time operational data regarding the availability and status of their resources to PJM, as described in detail in the PJM Manuals. Operational procedures are described in detail in the ***PJM Manual for Emergency Operations.***

Sections of the
PJM Open Access TransmissionTariff
and
PJM Operating Agreement

Clean Version

Additional coverpages separating Agreements

Sections of the
PJM Open Access TransmissionTariff

Clean Version

Definitions – R - S

1.36C Reasonable Efforts:

With respect to any action required to be made, attempted, or taken by an Interconnection Party or by a Construction Party under Part IV or Part VI of the Tariff, an Interconnection Service Agreement, or a Construction Service Agreement, such efforts as are timely and consistent with Good Utility Practice and with efforts that such party would undertake for the protection of its own interests.

1.37 Receiving Party:

The entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

1.37A Regional Transmission Expansion Plan:

The plan prepared by the Office of the Interconnection pursuant to Schedule 6 of the Operating Agreement for the enhancement and expansion of the Transmission System in order to meet the demands for firm transmission service in the PJM Region.

1.38 Regional Transmission Group (RTG):

A voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

1.38.01 Regulation Zone:

Any of those one or more geographic areas, each consisting of a combination of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, regulation service.

1.38.01A Relevant Electric Retail Regulatory Authority:

An entity that has jurisdiction over and establishes prices and policies for competition for providers of retail electric service to end-customers, such as the city council for a municipal utility, the governing board of a cooperative utility, the state public utility commission or any other such entity.

1.38A Reliability Assurance Agreement:

The Reliability Assurance Agreement Among Load Serving Entities in the PJM Region, Rate Schedule No. 44, dated as of May 28, 2009, and as amended from time to time thereafter.

1.38B [RESERVED]

1.38C Required Transmission Enhancements:

Enhancements and expansions of the Transmission System that (1) a Regional Transmission Expansion Plan developed pursuant to Schedule 6 of the Operating Agreement or (2) the Coordinated System Plan periodically developed pursuant to the Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. designates one or more of the Transmission Owner(s) or the transmission owners within the Midwest Independent System Operator to construct and own or finance.

1.38D Reserve Zone:

"Reserve Zone" shall mean any of those geographic areas consisting of a combination of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, reserve service.

1.39 Reserved Capacity:

The maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.39A Schedule of Work:

Shall mean that schedule attached to the Interconnection Construction Service Agreement setting forth the timing of work to be performed by the Constructing Entity pursuant to the Interconnection Construction Service Agreement, based upon the Facilities Study and subject to modification, as required, in accordance with Transmission Provider's scope change process for interconnection projects set forth in the PJM Manuals.

1.39B Scope of Work:

Shall mean that scope of the work attached as a schedule to the Interconnection Construction Service Agreement and to be performed by the Constructing Entity(ies) pursuant to the Interconnection Construction Service Agreement, provided that such Scope of Work may be modified, as required, in accordance with Transmission Provider's scope change process for interconnection projects set forth in the PJM Manuals.

1.39C Secondary Systems:

Control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers.

1.39D Security:

The security provided by the New Service Customer pursuant to Section 212.4 or Section 213.4 of the Tariff to secure the New Service Customer's responsibility for Costs under the Interconnection Service Agreement or Upgrade Construction Service Agreement and Section 217 of the Tariff.

1.40 Service Agreement:

The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

1.41 Service Commencement Date:

The date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Section 15.3 or Section 29.1 under the Tariff.

1.42 Short-Term Firm Point-To-Point Transmission Service:

Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of less than one year.

1.42a Site:

All of the real property, including but not limited to any leased real property and easements, on which the Customer Facility is situated and/or on which the Customer Interconnection Facilities are to be located.

1.42.01 Small Inverter Facility:

An Energy Resource that is a certified small inverter-based facility no larger than 10 kW.

1.42.02 Small Inverter ISA:

An agreement among Transmission Provider, Interconnection Customer, and Interconnected Transmission Owner regarding interconnection of a Small Inverter Facility under section 112B of Part IV of the Tariff.

1.42A [RESERVED]

1.42B [RESERVED]

1.42C [RESERVED]

1.42D State:

The term "state" shall mean a state of the United States or the District of Columbia.

1.42D.01 Switching and Tagging Rules:

The switching and tagging procedures of Interconnected Transmission Owners and Interconnection Customer as they may be amended from time to time.

1.42E [RESERVED]

1.42F System Condition:

A specified condition on the Transmission Provider's system or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm Point-to-Point Transmission Service using the curtailment priority pursuant to Section 13.6. Such conditions must be identified in the Transmission Customer's Service Agreement.

1.43 System Impact Study:

An assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a Completed Application, an Interconnection Request or an Upgrade Request, (ii) whether any additional costs may be incurred in order to provide such transmission service or to accommodate an Interconnection Request, and (iii) with respect to an Interconnection Request, an estimated date that an Interconnection Customer's Customer Facility can be interconnected with the Transmission System and an estimate of the Interconnection Customer's cost responsibility for the interconnection; and (iv) with respect to an Upgrade Request, the estimated cost of the requested system upgrades or expansion, or of the cost of the system upgrades or expansion, necessary to provide the requested incremental rights.

1.43.01 System Protection Facilities:

The equipment required to protect (i) the Transmission System, other delivery systems and/or other generating systems connected to the Transmission System from faults or other electrical disturbance occurring at or on the Customer Facility, and (ii) the Customer Facility from faults or other electrical system disturbance occurring on the Transmission System or on other delivery systems and/or other generating systems to which the Transmission System is directly or indirectly connected. System Protection Facilities shall include such protective and regulating devices as are identified in the Applicable Technical Requirements and Standards or that are required by Applicable Laws and Regulations or other Applicable Standards, or as are otherwise necessary to protect personnel and equipment and to minimize deleterious effects to the Transmission System arising from the Customer Facility.

SCHEDULE 3
Regulation and Frequency Response Service

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

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

a. Regulation shall be supplied to meet the Regulation objective of a Regulation Zone from resources located within the metered electrical boundaries of such Regulation Zone. Resources offering Regulation shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the PJM Manuals.

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

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

d. A resource capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced from the Regulation range by at least twice the amount of the Regulation provided with consideration of the Regulation limits of the resource, as specified in the PJM Manuals.

e. Qualified Regulation must satisfy the measurement and verification tests described in the PJM Manuals.

f. A Transmission Owner, Network Customer or other Transmission Customer may satisfy its Regulation obligation from its own resources capable of performing Regulation service, by contractual arrangements with others able to provide Regulation service on a comparable basis, or by purchases from the PJM Regulation market.

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

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

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

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

1.3 Definitions.

1.3.1 Acceleration Request.

"Acceleration Request" shall mean a request pursuant to section 1.9.4A of this Schedule to accelerate or reschedule a transmission outage scheduled pursuant to sections 1.9.2 or 1.9.4.

1.3.1A Auction Revenue Rights.

"Auction Revenue Rights" or "ARRs" shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Section 7.4 of this Schedule.

1.3.1B Auction Revenue Rights Credits.

"Auction Revenue Rights Credits" shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Section 7.4.3 of this Schedule.

1.3.1B.01 Batch Load Demand Resource.

"Batch Load Demand Resource" shall mean a Demand Resource that has a cyclical production process such that at most times during the process it is consuming energy, but at consistent regular intervals, ordinarily for periods of less than ten minutes, it reduces its consumption of energy for its production processes to minimal or zero megawatts.

1.3.1B.02 Congestion Price.

"Congestion Price" shall mean the congestion component of the Locational Marginal Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.1B.03 Curtailment Service Provider.

"Curtailment Service Provider" or "CSP" shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market by causing a reduction in demand.

1.3.1B.04 Day-ahead Congestion Price.

"Day-ahead Congestion Price" shall mean the Congestion Price resulting from the Day-ahead Energy Market.

1.3.1C Day-ahead Energy Market.

"Day-ahead Energy Market" shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Section 1.10 of this Schedule.

1.3.1C.01 Day-ahead Loss Price.

"Day-ahead Loss Price" shall mean the Loss Price resulting from the Day-ahead Energy Market.

1.3.1D Day-ahead Prices.

"Day-ahead Prices" shall mean the Locational Marginal Prices resulting from the Day-ahead Energy Market.

1.3.1D.01 Day-ahead Scheduling Reserves.

"Day-ahead Scheduling Reserves" shall mean thirty-minute reserves as defined by the Reliability First Corporation and SERC.

1.3.1D.02 Day-ahead Scheduling Reserves Requirement.

"Day-ahead Scheduling Reserves Requirement" shall mean the thirty-minute reserve requirement for the PJM Region established consistent with Reliability First Corporation and SERC reliability standards, or those of any additional and/or successor regional reliability organization(s) that are responsible for establishing reliability requirements for the PJM Region, plus any additional thirty-minute reserves scheduled in response to an RTO-wide Hot or Cold Weather Alert or other reasons for conservative operations.

1.3.1D.03 Day-ahead Scheduling Reserves Resources.

"Day-ahead Scheduling Reserves Resources" shall mean synchronized and non-synchronized generation resources and Demand Resources electrically located within the PJM Region that are capable of providing Day-ahead Scheduling Reserves.

1.3.1D.04 Day-ahead Scheduling Reserves Market.

"Day-ahead Scheduling Reserves Market" shall mean the schedule of commitments for the purchase or sale of Day-ahead Scheduling Reserves developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Section 1.10 of this Schedule.

1.3.1D.05 Day-ahead System Energy Price.

"Day-ahead System Energy Price" shall mean the System Energy Price resulting from the Day-ahead Energy Market.

1.3.1E Decrement Bid.

"Decrement Bid" shall mean a bid to purchase energy at a specified location in the Day-ahead Energy Market. An accepted Decrement Bid results in scheduled load at the specified location in the Day-ahead Energy Market.

1.3.1E.01 Demand Resource.

"Demand Resource" shall mean a resource with the capability to provide a reduction in demand.

1.3.1F Dispatch Rate.

"Dispatch Rate" shall mean the control signal, expressed in dollars per megawatt-hour, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by the Office of the Interconnection in accordance with the Offer Data.

1.3.1G Energy Storage Resource.

"Energy Storage Resource" shall mean flywheel or battery storage facility solely used for short term storage and injection of energy at a later time to participate in the PJM energy and/or Ancilliary Services markets as a Market Seller.

1.3.2 Equivalent Load.

"Equivalent Load" shall mean the sum of a Market Participant's net system requirements to serve its customer load in the PJM Region, if any, plus its net bilateral transactions.

1.3.2A Economic Load Response Participant.

"Economic Load Response Participant" shall mean a Member or Special Member that qualifies under Section 1.5A of this Schedule to participate in the PJM Interchange Energy Market through reductions in demand.

1.3.2A.01 Economic Minimum.

"Economic Minimum" shall mean the lowest incremental MW output level a unit can achieve while following economic dispatch.

1.3.2B Energy Market Opportunity Cost.

"Energy Market Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of available run hours due to limitations imposed on the unit by Applicable Laws and Regulations (as defined in PJM Tariff), and (b) the forecasted future hourly Locational Marginal Price at which the generating

unit could run while not violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Schedule 2 of the Operating Agreement.

1.3.3 External Market Buyer.

"External Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for consumption by end-users outside the PJM Region, or for load in the PJM Region that is not served by Network Transmission Service.

1.3.4 External Resource.

"External Resource" shall mean a generation resource located outside the metered boundaries of the PJM Region.

1.3.5 Financial Transmission Right.

"Financial Transmission Right" or "FTR" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2 of this Schedule.

1.3.5A Financial Transmission Right Obligation.

"Financial Transmission Right Obligation" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2(b) of this Schedule.

1.3.5B Financial Transmission Right Option.

"Financial Transmission Right Option" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2(c) of this Schedule.

1.3.6 Generating Market Buyer.

"Generating Market Buyer" shall mean an Internal Market Buyer that is a Load Serving Entity that owns or has contractual rights to the output of generation resources capable of serving the Market Buyer's load in the PJM Region, or of selling energy or related services in the PJM Interchange Energy Market or elsewhere.

1.3.7 Generator Forced Outage.

"Generator Forced Outage" shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the PJM Manuals. A reduction in output or

removal from service of a generating unit in response to changes in market conditions shall not constitute a Generator Forced Outage.

1.3.8 Generator Maintenance Outage.

"Generator Maintenance Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform necessary repairs on specific components of the facility, if removal of the facility meets the guidelines specified in the PJM Manuals.

1.3.9 Generator Planned Outage.

"Generator Planned Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the Office of the Interconnection in accordance with the PJM Manuals.

1.3.9A Increment Bid.

"Increment Bid" shall mean an offer to sell energy at a specified location in the Day-ahead Energy Market. An accepted Increment Bid results in scheduled generation at the specified location in the Day-ahead Energy Market.

1.3.9B Interface Pricing Point.

"Interface Pricing Point" shall have the meaning specified in section 2.6A.

1.3.10 Internal Market Buyer.

"Internal Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for ultimate consumption by end-users inside the PJM Region that are served by Network Transmission Service.

1.3.11 Inadvertent Interchange.

"Inadvertent Interchange" shall mean the difference between net actual energy flow and net scheduled energy flow into or out of the individual Control Areas operated by PJM.

1.3.11.01 Load Management.

"Load Management" shall mean either a Demand Resource ("DR") or an Interruptible Load for Reliability ("ILR") resource, both as defined in the Reliability Assurance Agreement.

1.3.11A Load Reduction Event.

"Load Reduction Event" shall mean a reduction in demand by a Member or Special Member for the purpose of participating in the PJM Interchange Energy Market.

1.3.11B Loss Price.

"Loss Price" shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.12 Market Operations Center.

"Market Operations Center" shall mean the equipment, facilities and personnel used by or on behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

1.3.12A Maximum Emergency.

"Maximum Emergency" shall mean the designation of all or part of the output of a generating unit for which the designated output levels may require extraordinary procedures and therefore are available to the Office of the Interconnection only when the Office of the Interconnection declares a Maximum Generation Emergency and requests generation designated as Maximum Emergency to run. The Office of the Interconnection shall post on the PJM website the aggregate amount of megawatts that are classified as Maximum Emergency.

1.3.13 Maximum Generation Emergency.

"Maximum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection to address either a generation or transmission emergency in which the Office of the Interconnection anticipates requesting one or more Generation Capacity Resources, or Non-Retail Behind The Meter Generation resources to operate at its maximum net or gross electrical power output, subject to the equipment stress limits for such Generation Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

1.3.14 Minimum Generation Emergency.

"Minimum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

1.3.14A NERC Interchange Distribution Calculator.

"NERC Interchange Distribution Calculator" shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

1.3.14B Net Benefits Test.

"Net Benefits Test" shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Section 3.3A.4 of this Schedule.

1.3.15 Network Resource.

"Network Resource" shall have the meaning specified in the PJM Tariff.

1.3.16 Network Service User.

"Network Service User" shall mean an entity using Network Transmission Service.

1.3.17 Network Transmission Service.

"Network Transmission Service" shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part III of the PJM Tariff, or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

1.3.17A Non-Regulatory Opportunity Cost.

"Non-Regulatory Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, (ii) a fuel supply limitation, for up to one year, resulting from an event of force majeure; and, (b) the forecasted future hourly Locational Marginal Price at which the generating unit could run while not violating such limitations. Non-Regulatory Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same period of time in which the unit is bound by the referenced restrictions, and is reflected in the rules set forth in PJM Manual 15. Non-Regulatory Opportunity Costs shall be limited to those resources which are specifically delineated in Schedule 2 of the Operating Agreement.

1.3.17B Non-Synchronized Reserve.

"Non-Synchronized Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

1.3.17C Non-Synchronized Reserve Event.

"Non-Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources and/or Demand Resources able, assigned or self-scheduled, to provide

Non-Synchronized Reserve within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-schedule Non-Synchronized Reserve capability.

1.3.17D Non-Variable Loads.

"Non-Variable Loads" shall have the meaning specified in section 1.5A.6 of this Schedule.

1.3.18 Normal Maximum Generation.

"Normal Maximum Generation" shall mean the highest output level of a generating resource under normal operating conditions.

1.3.19 Normal Minimum Generation.

"Normal Minimum Generation" shall mean the lowest output level of a generating resource under normal operating conditions.

1.3.20 Offer Data.

"Offer Data" shall mean the scheduling, operations planning, dispatch, new resource, and other data and information necessary to schedule and dispatch generation resources and Demand Resource(s) for the provision of energy and other services and the maintenance of the reliability and security of the transmission system in the PJM Region, and specified for submission to the PJM Interchange Energy Market for such purposes by the Office of the Interconnection.

1.3.21 Office of the Interconnection Control Center.

"Office of the Interconnection Control Center" shall mean the equipment, facilities and personnel used by the Office of the Interconnection to coordinate and direct the operation of the PJM Region and to administer the PJM Interchange Energy Market, including facilities and equipment used to communicate and coordinate with the Market Participants in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

1.3.21A On-Site Generators.

"On-Site Generators" shall mean generation facilities (including Behind The Meter Generation) that (i) are not Capacity Resources, (ii) are not injecting into the grid, (iii) are either synchronized or non-synchronized to the Transmission System, and (iv) can be used to reduce demand for the purpose of participating in the PJM Interchange Energy Market.

1.3.22 Operating Day.

"Operating Day" shall mean the daily 24 hour period beginning at midnight for which transactions on the PJM Interchange Energy Market are scheduled.

1.3.23 Operating Margin.

"Operating Margin" shall mean the incremental adjustments, measured in megawatts, required in PJM Region operations in order to accommodate, on a first contingency basis, an operating contingency in the PJM Region resulting from operations in an interconnected Control Area. Such adjustments may result in constraints causing Transmission Congestion Charges, or may result in Ancillary Services charges pursuant to the PJM Tariff.

1.3.24 Operating Margin Customer.

"Operating Margin Customer" shall mean a Control Area purchasing Operating Margin pursuant to an agreement between such other Control Area and the LLC.

1.3.25 PJM Interchange.

"PJM Interchange" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load exceeds, or is exceeded by, the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup; or (c) the hourly scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the hourly net metered output of any other Market Seller; or (e) the hourly scheduled deliveries of Spot Market Energy to an External Market Buyer; or (f) the hourly scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

1.3.26 PJM Interchange Export.

"PJM Interchange Export" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load is exceeded by the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup sales; or (c) the hourly scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the hourly net metered output of any other Market Seller.

1.3.27 PJM Interchange Import.

"PJM Interchange Import" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load exceeds the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup purchases; or (c) the hourly scheduled deliveries of Spot Market Energy to an External Market Buyer; or (d) the hourly scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

1.3.28 PJM Open Access Same-time Information System.

"PJM Open Access Same-time Information System" shall mean the electronic communication system for the collection and dissemination of information about transmission services in the PJM Region, established and operated by the Office of the Interconnection in accordance with FERC standards and requirements.

1.3.28A Planning Period Quarter.

"Planning Period Quarter" shall mean any of the following three month periods in the Planning Period: June, July and August; September, October and November; December, January and February; or, March, April and May.

1.3.28B Planning Period Balance.

"Planning Period Balance" shall mean the entire period of time remaining in the Planning Period following the month that a monthly auction is conducted.

1.3.29 Point-to-Point Transmission Service.

"Point-to-Point Transmission Service" shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part II of the PJM Tariff.

1.3.29A PRD Curve

PRD Curve shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29B PRD Provider

PRD Provider shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29C PRD Reservation Price

PRD Reservation Price shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29D PRD Substation

PRD Substation shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29E Price Responsive Demand

Price Responsive Demand shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29F Primary Reserve

"Primary Reserve" shall mean the total reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes of a request from the Office of the Interconnection dispatcher, and is comprised of both Synchronized Reserve and Non-Synchronized Reserve.

1.3.30 Ramping Capability.

"Ramping Capability" shall mean the sustained rate of change of generator output, in megawatts per minute.

1.3.30.01 Real-time Congestion Price.

"Real-time Congestion Price" shall mean the Congestion Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30.02 Real-time Loss Price.

"Real-time Loss Price" shall mean the Loss Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30A Real-time Prices.

"Real-time Prices" shall mean the Locational Marginal Prices resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30B Real-time Energy Market.

"Real-time Energy Market" shall mean the purchase or sale of energy and payment of Transmission Congestion Charges for quantity deviations from the Day-ahead Energy Market in the Operating Day.

1.3.30B.01 Real-time System Energy Price.

"Real-time System Energy Price" shall mean the System Energy Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.31 Regulation.

"Regulation" shall mean the capability of a specific generation resource or Demand Resource with appropriate telecommunications, control and response capability to increase or decrease its output or adjust load in response to a regulating control signal, in accordance with the specifications in the PJM Manuals.

1.3.31.001 Reserve Penalty Factor.

"Reserve Penalty Factor" shall mean the cost, in $/MWh, associated with being unable to meet a specific reserve requirement in a Reserve Zone. A Reserve Penalty Factor will be defined for each reserve requirement in a Reserve Zone.

1.3.31.01 Residual Auction Revenue Rights.

"Residual Auction Revenue Rights" shall mean incremental stage 1 Auction Revenue Rights created within a Planning Period by an increase in transmission system capability or a change in any other relevant factor that was not modeled pursuant to section 7.5 of Schedule 1 of this Agreement in compliance with section 7.4.2 (h) of Schedule 1 of this Agreement, and, if modeled, would have increased the amount of stage 1 Auction Revenue Rights allocated pursuant to section 7.4.2 of Schedule 1 of this Agreement; provided that, the foregoing notwithstanding, Residual Auction Revenue Rights shall exclude: 1) Incremental Auction Revenue Rights allocated pursuant to Part VI of the Tariff; and 2) Auction Revenue Rights allocated to entities that are assigned cost responsibility pursuant to Schedule 6 of this Agreement for transmission upgrades that create such rights.

1.3.31.02 Special Member.

"Special Member" shall mean an entity that satisfies the requirements of Section 1.5A.02 of this Schedule or the special membership provisions established under the Emergency Load Response Program.

1.3.31A [Reserved.]

1.3.31B [Reserved.]

1.3.32 Spot Market Backup.

"Spot Market Backup" shall mean the purchase of energy from, or the delivery of energy to, the PJM Interchange Energy Market in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason.

1.3.33 Spot Market Energy.

"Spot Market Energy" shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at System Energy Prices determined as specified in Section 2 of this Schedule.

1.3.33A State Estimator.

"State Estimator" shall mean the computer model of power flows specified in Section 2.3 of this Schedule.

1.3.33B Station Power.

"Station Power" shall mean energy used for operating the electric equipment on the site of a generation facility located in the PJM Region or for the heating, lighting, air-conditioning and office equipment needs of buildings on the site of such a generation facility that are used in the operation, maintenance, or repair of the facility. Station Power does not include any energy (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility; (iii) used for compressors at a compressed air energy storage facility; (iv) used for charging an Energy Storage Resource; or (v) used in association with restoration or black start service.

1.3.33B.01 Synchronized Reserve.

"Synchronized Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes from the request of the Office of the Interconnection dispatcher, and is provided by equipment that is electrically synchronized to the Transmission System.

1.3.33B.02 Synchronized Reserve Event.

"Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources and/or Demand Resources able, assigned or self-scheduled, to provide Synchronized Reserve within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-scheduled Synchronized Reserve capability.

1.3.33B.03 System Energy Price.

"System Energy Price" shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.33C Target Allocation.

"Target Allocation" shall mean the allocation of Transmission Congestion Credits as set forth in Section 5.2.3 of this Schedule or the allocation of Auction Revenue Rights Credits as set forth in Section 7.4.3 of this Schedule.

1.3.34 Transmission Congestion Charge.

"Transmission Congestion Charge" shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses in accordance with Section 9.3, which shall be calculated and allocated as specified in Section 5.1 of this Schedule.

1.3.35 Transmission Congestion Credit.

"Transmission Congestion Credit" shall mean the allocated share of total Transmission Congestion Charges credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section 5.2 of this Schedule.

1.3.36 Transmission Customer.

"Transmission Customer" shall mean an entity using Point-to-Point Transmission Service.

1.3.37 Transmission Forced Outage.

"Transmission Forced Outage" shall mean an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the PJM Manuals. A removal from service of a transmission facility at the request of the Office of the Interconnection to improve transmission capability shall not constitute a Forced Transmission Outage.

1.3.37A Transmission Loading Relief.

"Transmission Loading Relief" shall mean NERC's procedures for preventing operating security limit violations, as implemented by PJM as the security coordinator responsible for maintaining transmission security for the PJM Region.

1.3.37B Transmission Loading Relief Customer.

"Transmission Loading Relief Customer" shall mean an entity that, in accordance with Section 1.10.6A, has elected to pay Transmission Congestion Charges during Transmission Loading Relief in order to continue energy schedules over contract paths outside the PJM Region that are increasing the cost of energy in the PJM Region.

1.3.37C Transmission Loss Charge.

"Transmission Loss Charge" shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Section 5 of this Schedule.

1.3.38 Transmission Planned Outage.

"Transmission Planned Outage" shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in this Agreement or the PJM Manuals.

1.3.38A Variable Loads.

"Variable Loads" shall have the meaning specified in section 1.5A.6 of this Schedule.

1.3.39 Zonal Base Load.

"Zonal Base Load" shall mean the lowest daily zonal peak load from the twelve month period ending October 21 of the calendar year immediately preceding the calendar year in which an annual Auction Revenue Right allocation is conducted, increased by the projected load growth rate for the relevant Zone.

1.7 General.

1.7.1 Market Sellers.

Only Market Sellers shall be eligible to submit offers to the Office of the Interconnection for the sale of electric energy or related services in the PJM Interchange Energy Market. Market Sellers shall comply with the prices, terms, and operating characteristics of all Offer Data submitted to and accepted by the PJM Interchange Energy Market.

1.7.2 Market Buyers.

Only Market Buyers shall be eligible to purchase energy or related services in the PJM Interchange Energy Market. Market Buyers shall comply with all requirements for making purchases from the PJM Interchange Energy Market.

1.7.2A Economic Load Response Participants.

Only Economic Load Response Participants shall be eligible to participate in the Real-time Energy Market and the Day-ahead Energy Market by submitting offers to the Office of the Interconnection to reduce demand.

1.7.3 Agents.

A Market Participant may participate in the PJM Interchange Energy Market through an agent, provided that the Market Participant informs the Office of the Interconnection in advance in writing of the appointment of such agent. A Market Participant participating in the PJM Interchange Energy Market through an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the PJM Interchange Energy Market, and shall ensure that any such agent complies with the requirements of this Agreement.

1.7.4 General Obligations of the Market Participants.

(a) In performing its obligations to the Office of the Interconnection hereunder, each Market Participant shall at all times (i) follow Good Utility Practice, (ii) comply with all applicable laws and regulations, (iii) comply with the applicable principles, guidelines, standards and requirements of FERC, NERC and Applicable Regional Reliability Councils, (iv) comply with the procedures established for operation of the PJM Interchange Energy Market and PJM Region and (v) cooperate with the Office of the Interconnection as necessary for the operation of the PJM Region in a safe, reliable manner consistent with Good Utility Practice.

(b) Market Participants shall undertake all operations in or affecting the PJM Interchange Energy Market and the PJM Region including but not limited to compliance with all Emergency procedures, in accordance with the power and authority of the Office of the Interconnection with respect to the operation of the PJM Interchange Energy Market and the PJM Region as established in this Agreement, and as specified in the Schedules to this Agreement and the PJM Manuals. Failure to comply with the foregoing operational

requirements shall subject a Market Participant to such reasonable charges or other remedies or sanctions for non-compliance as may be established by the PJM Board, including legal or regulatory proceedings as authorized by the PJM Board to enforce the obligations of this Agreement.

(c) The Office of the Interconnection may establish such committees with a representative of each Market Participant, and the Market Participants agree to provide appropriately qualified personnel for such committees, as may be necessary for the Office of the Interconnection and PJMSettlement to perform its obligations hereunder.

(d) All Market Participants shall provide to the Office of the Interconnection the scheduling and other information specified in the Schedules to this Agreement, and such other information as the Office of the Interconnection may reasonably require for the reliable and efficient operation of the PJM Region and PJM Interchange Energy Market, and for compliance with applicable regulatory requirements for posting market and related information. Such information shall be provided as much in advance as possible, but in no event later than the deadlines established by the Schedules to this Agreement, or by the Office of the Interconnection in conformance with such Schedules. Such information shall include, but not be limited to, maintenance and other anticipated outages of generation or transmission facilities, scheduling and related information on bilateral transactions and self-scheduled resources, and implementation of active load management, interruption of load, Price Responsive Demand, and other load reduction measures. The Office of the Interconnection shall abide by appropriate requirements for the non-disclosure and protection of any confidential or proprietary information given to the Office of the Interconnection by a Market Participant. Each Market Participant shall maintain or cause to be maintained compatible information and communications systems, as specified by the Office of the Interconnection, required to transmit scheduling, dispatch, or other time-sensitive information to the Office of the Interconnection in a timely manner.

(e) Subject to the requirements for Economic Load Response Participants in section 1.5A above, each Market Participant shall install and operate, or shall otherwise arrange for, metering and related equipment capable of recording and transmitting all voice and data communications reasonably necessary for the Office of the Interconnection and PJMSettlement to perform the services specified in this Agreement. A Market Participant that elects to be separately billed for its PJM Interchange shall, to the extent necessary, be individually metered in accordance with Section 14 of this Agreement, or shall agree upon an allocation of PJM Interchange between it and the Market Participant through whose meters the unmetered Market Participant's PJM Interchange is delivered. The Office of the Interconnection shall be notified of the allocation by the foregoing Market Participants.

(f) Each Market Participant shall operate, or shall cause to be operated, any generating resources owned or controlled by such Market Participant that are within the PJM Region or otherwise supplying energy to or through the PJM Region in a manner that is consistent with the standards, requirements or directions of the Office of the Interconnection and that will permit the Office of the Interconnection to perform its obligations under this Agreement; provided, however, no Market Participant shall be required to take any action that is inconsistent with Good Utility Practice or applicable law.

(g) Each Market Participant shall follow the directions of the Office of the Interconnection to take actions to prevent, manage, alleviate or end an Emergency in a manner consistent with this Agreement and the procedures of the PJM Region as specified in the PJM Manuals.

(h) Each Market Participant shall obtain and maintain all permits, licenses or approvals required for the Market Participant to participate in the PJM Interchange Energy Market in the manner contemplated by this Agreement.

(i) Consistent with Section 36.1.1 of the PJM Tariff, to the extent its generating facility is dispatchable, a Market Participant shall submit an Economic Minimum in the Real-time Energy Market that is no greater than the higher of its physical operating minimum or its Capacity Interconnection Rights, as that term is defined in the PJM Tariff, associated with such generating facility under its Interconnection Service Agreement under Attachment O of the PJM Tariff or a wholesale market participation agreement.

1.7.5 Market Operations Center.

Each Market Participant shall maintain a Market Operations Center, or shall make appropriate arrangements for the performance of such services on its behalf. A Market Operations Center shall meet the performance, equipment, communications, staffing and training standards and requirements specified in this Agreement for the scheduling and completion of transactions in the PJM Interchange Energy Market and the maintenance of the reliable operation of the PJM Region, and shall be sufficient to enable (i) a Market Seller or an Economic Load Response Participant to perform all terms and conditions of its offers to the PJM Interchange Energy Market, and (ii) a Market Buyer or an Economic Load Response Participant to conform to the requirements for purchasing from the PJM Interchange Energy Market.

1.7.6 Scheduling and Dispatching.

(a) The Office of the Interconnection shall schedule and dispatch in real-time generation resources and/or Demand Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Sellers, continuing until sufficient generation resources and/or Demand Resources are dispatched to serve the PJM Interchange Energy Market energy purchase requirements under normal system conditions of the Market Buyers (taking into account any reductions to such requirements in accordance with PRD Curves properly submitted by PRD Providers), as well as the requirements of the PJM Region for ancillary services provided by generation resources and/or Demand Resources, in accordance with this Agreement. Such scheduling and dispatch shall recognize transmission constraints on coordinated flowgates external to the Transmission System in accordance with Appendix A to the Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38) and on other such flowgates that are coordinated in accordance with

agreements between the LLC and other entities. Scheduling and dispatch shall be conducted in accordance with this Agreement.

(b) The Office of the Interconnection shall undertake to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the PJM Interchange Energy Market, and any relevant procedures of another Control Area, or any tariff (including the PJM Tariff). Upon determining that any such conflict or incompatibility exists, the Office of the Interconnection shall propose tariff or procedural changes, and undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

(c) To protect its generation or distribution facilities, or local Transmission Facilities not under the monitoring responsibility and dispatch control of the Office of the Interconnection, an entity may request that the Office of the Interconnection schedule and dispatch generation or reductions in demand to meet a limit on Transmission Facilities different from that which the Office of the Interconnection has determined to be required for reliable operation of the Transmission System. To the extent consistent with its other obligations under this Agreement, the Office of the Interconnection shall schedule and dispatch generation and reductions in demand in accordance with such request. An entity that makes a request pursuant to this section 1.7.6(c) shall be responsible for all generation and other costs resulting from its request that would not have been incurred by operating the Transmission System and scheduling and dispatching generation in the manner that the Office of the Interconnection otherwise has determined to be required for reliable operation of the Transmission System.

1.7.7 Pricing.

The price paid for energy bought and sold in the PJM Interchange Energy Market and for demand reductions will reflect the hourly Locational Marginal Price at each load and generation bus, determined by the Office of the Interconnection in accordance with this Agreement. Transmission Congestion Charges and Transmission Loss Charges, which shall be determined by differences in Congestion Prices and Loss Prices in an hour, shall be calculated by the Office of the Interconnection, and collected by PJMSettlement, and the revenues therefrom shall be disbursed by PJMSettlement in accordance with this Schedule.

1.7.8 Generating Market Buyer Resources.

A Generating Market Buyer may elect to self-schedule its generation resources up to that Generating Market Buyer's Equivalent Load, in accordance with and subject to the procedures specified in this Schedule, and the accounting and billing requirements specified in Section 3 to this Schedule. PJMSettlement shall not be a contracting party with respect to such self-scheduled or self-supplied transactions.

1.7.9 Delivery to an External Market Buyer.

A purchase of Spot Market Energy by an External Market Buyer shall be delivered to a bus or busses at the electrical boundaries of the PJM Region specified by the Office of the Interconnection, or to load in such area that is not served by Network Transmission Service,

using Point-to-Point Transmission Service paid for by the External Market Buyer. Further delivery of such energy shall be the responsibility of the External Market Buyer.

1.7.10 Other Transactions.

(a) Bilateral Transactions.

(i) In addition to transactions in the PJM Interchange Energy Market, Market Participants may enter into bilateral contracts for the purchase or sale of electric energy to or from each other or any other entity, subject to the obligations of Market Participants to make Generation Capacity Resources available for dispatch by the Office of the Interconnection. Such bilateral contracts shall be for the physical transfer of energy to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its eSchedules and Enhanced Energy Scheduler tools.

(ii) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of energy to a Market Participant inside the PJM Region, title to the energy that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and the further transmission of the energy or further sale of the energy into the PJM Interchange Energy Market shall be transacted by the buyer under the bilateral contract. With respect to all bilateral contracts for the physical transfer of energy to an entity outside the PJM Region, title to the energy shall pass to the buyer at the border of the PJM Region and shall be delivered to the border using transmission service. In no event shall the purchase and sale of energy between Market Participants under a bilateral contract constitute a transaction in the PJM Interchange Energy Market or be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

(iii) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of energy reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the megawatt hours of such reported transactions to amounts reflecting the expected load and other physical delivery obligations of the buyer under the bilateral contract.

(iv) All payments and related charges for the energy associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. 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 a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

(v) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any Spot Market Backup used to meet the bilateral contract seller's obligation to deliver energy under the bilateral contract and

for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new eSchedules or Enhanced Energy Scheduler reporting by the Market Participant and (ii) terminate all of the Market Participant's eSchedules and Enhanced Energy Schedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the eSchedules and Enhanced Energy Schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection. PJMSettlement shall assign its claims against a seller with respect to a seller's nonpayment for Spot Market Backup to a buyer to the extent that the buyer has made an indemnification payment to PJMSettlement with respect to the seller's nonpayment.

(vi) Bilateral contracts that do not contemplate the physical transfer of energy to or from a Market Participant are not subject to this Schedule, shall not be reported to and coordinated with the Office of the Interconnection, and shall not in any way constitute a transaction in the PJM Interchange Energy Market.

(b) Market Participants shall have Spot Market Backup with respect to all bilateral transactions that contemplate the physical transfer of energy to or from a Market Participant, that are not dynamically scheduled pursuant to Section 1.12 and that are curtailed or interrupted for any reason (except for curtailments or interruptions through active load management for load located within the PJM Region).

(c) To the extent the Office of the Interconnection dispatches a Generating Market Buyer's generation resources, such Generating Market Buyer may elect to net the output of such resources against its hourly Equivalent Load. Such a Generating Market Buyer shall be deemed a buyer from the PJM Interchange Energy Market to the extent of its PJM Interchange Imports, and shall be deemed a seller to the PJM Interchange Energy Market to the extent of its PJM Interchange Exports.

(d) A Market Seller may self-supply Station Power for its generation facility in accordance with the following provisions:

(i) A Market Seller may self-supply Station Power for its generation facility during any month (1) when the net output of such facility is positive, or (2) when the net output of such facility is negative and the Market Seller during the same month has available at other of its generation facilities positive net output in an amount at least sufficient to offset fully such negative net output. For purposes of this subsection (d), "net output" of a generation facility during any month means the facility's gross energy output, less the Station Power requirements of such facility, during that month. The determination of a generation facility's or a Market Seller's monthly net output under this subsection (d) will apply only to determine whether the Market Seller self-supplied

Station Power during the month and will not affect the price of energy sold or consumed by the Market Seller at any bus during any hour during the month. For each hour when a Market Seller has positive net output and delivers energy into the Transmission System, it will be paid the LMP at its bus for that hour for all of the energy delivered. Conversely, for each hour when a Market Seller has negative net output and has received Station Power from the Transmission System, it will pay the LMP at its bus for that hour for all of the energy consumed.

(ii) Transmission Provider will determine the extent to which each affected Market Seller during the month self-supplied its Station Power requirements or obtained Station Power from third-party providers (including affiliates) and will incorporate that determination in its accounting and billing for the month. In the event that a Market Seller self-supplies Station Power during any month in the manner described in subsection (1) of subsection (d)(i) above, Market Seller will not use, and will not incur any charges for, transmission service. In the event, and to the extent, that a Market Seller self-supplies Station Power during any month in the manner described in subsection (2) of subsection (d)(i) above (hereafter referred to as "remote self-supply of Station Power"), Market Seller shall use and pay for transmission service for the transmission of energy in an amount equal to the facility's negative net output from Market Seller's generation facility(ies) having positive net output. Unless the Market Seller makes other arrangements with Transmission Provider in advance, such transmission service shall be provided under Part II of the PJM Tariff and shall be charged the hourly rate under Schedule 8 of the PJM Tariff for Non-Firm Point-to-Point Transmission Service with an election to pay congestion charges, provided, however, that no reservation shall be necessary for such transmission service and the terms and charges under Schedules 1, 1A, 2 through 6, 9 and 10 of the PJM Tariff shall not apply to such service. The amount of energy that a Market Seller transmits in conjunction with remote self-supply of Station Power will not be affected by any other sales, purchases, or transmission of capacity or energy by or for such Market Seller under any other provisions of the PJM Tariff.

(iii) A Market Seller may self-supply Station Power from its generation facilities located outside of the PJM Region during any month only if such generation facilities in fact run during such month and Market Seller separately has reserved transmission service and scheduled delivery of the energy from such resource in advance into the PJM Region.

1.7.11 Emergencies.

(a) The Office of the Interconnection, with the assistance of the Members' dispatchers as it may request, shall be responsible for monitoring the operation of the PJM Region, for declaring the existence of an Emergency, and for directing the operations of Market Participants as necessary to manage, alleviate or end an Emergency. The standards, policies and procedures of the Office of the Interconnection for declaring the existence of an Emergency, including but not limited to a Minimum Generation Emergency, and for managing, alleviating or ending an Emergency, shall apply to all Members on a non-discriminatory basis. Actions by the Office of the Interconnection and the Market Participants shall be carried out in accordance with

this Agreement, the NERC Operating Policies, Applicable Regional Reliability Council reliability principles and standards, Good Utility Practice, and the PJM Manuals. A declaration that an Emergency exists or is likely to exist by the Office of the Interconnection shall be binding on all Market Participants until the Office of the Interconnection announces that the actual or threatened Emergency no longer exists. Consistent with existing contracts, all Market Participants shall comply with all directions from the Office of the Interconnection for the purpose of managing, alleviating or ending an Emergency. The Market Participants shall authorize the Office of the Interconnection and PJMSettlement to purchase or sell energy on their behalf to meet an Emergency, and otherwise to implement agreements with other Control Areas interconnected with the PJM Region for the mutual provision of service to meet an Emergency, in accordance with this Agreement.

(b) To the extent load must be shed to alleviate an Emergency in a Control Zone, the Office of the Interconnection shall, to the maximum extent practicable, direct the shedding of load within such Control Zone. The Office of the Interconnection may shed load in one Control Zone to alleviate an Emergency in another Control Zone under its control only as necessary after having first shed load to the maximum extent practicable in the Control Zone experiencing the Emergency and only to the extent that PJM supports other control areas (not under its control) in those situations where load shedding would be necessary, such as to prevent isolation of facilities within the Eastern Interconnection, to prevent voltage collapse, or to restore system frequency following a system collapse; provided, however, that the Office of the Interconnection may not order a manual load dump in a Control Zone solely to address capacity deficiencies in another Control Zone. This section shall be implemented consistent with the North American Electric Reliability Council and applicable reliability council standards.

1.7.12 Fees and Charges.

Each Market Participant, except for Special Members, shall pay all fees and charges of the Office of the Interconnection for operation of the PJM Interchange Energy Market as determined by and allocated to the Market Participant by the Office of the Interconnection in accordance with Schedule 3.

1.7.13 Relationship to the PJM Region.

The PJM Interchange Energy Market operates within and subject to the requirements for the operation of the PJM Region.

1.7.14 PJM Manuals.

The Office of the Interconnection shall be responsible for maintaining, updating, and promulgating the PJM Manuals as they relate to the operation of the PJM Interchange Energy Market. The PJM Manuals, as they relate to the operation of the PJM Interchange Energy Market, shall conform and comply with this Agreement, NERC operating policies, and Applicable Regional Reliability Council reliability principles, guidelines and standards, and shall be designed to facilitate administration of an efficient energy market within industry reliability standards and the physical capabilities of the PJM Region.

1.7.15 Corrective Action.

Consistent with Good Utility Practice, the Office of the Interconnection shall be authorized to direct or coordinate corrective action, whether or not specified in the PJM Manuals, as necessary to alleviate unusual conditions that threaten the integrity or reliability of the PJM Region, or the regional power system.

1.7.16 Recording.

Subject to the requirements of applicable State or federal law, all voice communications with the Office of the Interconnection Control Center may be recorded by the Office of the Interconnection and any Market Participant communicating with the Office of the Interconnection Control Center, and each Market Participant hereby consents to such recording.

1.7.17 Operating Reserves.

(a) The following procedures shall apply to any generation unit subject to the dispatch of the Office of the Interconnection for which construction commenced before July 9, 1996, or any Demand Resource subject to the dispatch of the Office of the Interconnection.

(b) The Office of the Interconnection shall schedule to the Operating Reserve and load-following objectives of the Control Zones of the PJM Region and the PJM Interchange Energy Market in scheduling generation resources and/or Demand Resources pursuant to this Schedule. A table of Operating Reserve objectives for each Control Zone is calculated and published annually in the PJM Manuals. Reserve levels are probabilistically determined based on the season's historical load forecasting error and forced outage rates.

(c) Nuclear generation resources shall not be eligible for Operating Reserve payments unless: 1) the Office of the Interconnection directs such resources to reduce output, in which case, such units shall be compensated in accordance with section 3.2.3(f) of this Schedule; or 2) the resource submits a request for a risk premium to the Market Monitoring Unit under the procedures specified in Section II.B of Attachment M - Appendix. A nuclear generation resource (i) must submit a risk premium consistent with its agreement under such process, or, (ii) if it has not agreed with the Market Monitoring Unit on an appropriate risk premium, may submit its own determination of an appropriate risk premium to the Office of the Interconnection, subject to acceptance by the Office of the Interconnection, with or without prior approval from the Commission.

(d) PJMSettlement shall be the Counterparty to the purchases and sales of Operating Reserve in the PJM Interchange Energy Market.

1.7.18 Regulation.

(a) Regulation to meet the Regulation objective of each Regulation Zone shall be supplied from generation resources and/or Demand Resources located within the metered

electrical boundaries of such Regulation Zone. Generating Market Buyers, and Market Sellers offering Regulation, shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the PJM Manuals.

(b) The Office of the Interconnection shall obtain and maintain for each Regulation Zone an amount of Regulation equal to the Regulation objective for such Regulation Zone as specified in the PJM Manuals.

(c) The Regulation range of a generation unit or Demand Resource shall be at least twice the amount of Regulation assigned as described in the PJM Manuals.

(d) A resource capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced by at least twice the amount of the Regulation provided with consideration of the Regulation limits of that resource, as specified in the PJM Manuals.

(e) Qualified Regulation must satisfy the measurement and verification tests described in the PJM Manuals.

1.7.19 Ramping.

A generator dispatched by the Office of the Interconnection pursuant to a control signal appropriate to increase or decrease the generator's megawatt output level shall be able to change output at the ramping rate specified in the Offer Data submitted to the Office of the Interconnection for that generator.

1.7.19A Synchronized Reserve.

(a) Synchronized Reserve shall be supplied from generation resources and/or Demand Resources located within the metered boundaries of the PJM Region. Generating Market Buyers, and Market Sellers offering Synchronized Reserve shall comply with applicable standards and requirements for Synchronized Reserve capability and dispatch specified in the PJM Manuals

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone an amount of *Primary and* Synchronized Reserve equal to the *respective Primary and* Synchronized Reserve objective*s* for such Reserve Zone, as specified in the PJM Manuals.

(c) The Synchronized Reserve capability of a generation resource and Demand Resource shall be the increase in energy output or load reduction achievable by the generation resource and Demand Resource within a continuous 10-minute period.

(d) A generation unit capable of automatic energy dispatch that also is providing Synchronized Reserve shall have its energy dispatch range reduced by the amount of the Synchronized Reserve provided. The amount of Synchronized Reserve provided by a generation unit shall serve to redefine the Normal Maximum Generation energy limit of that generation unit

in that the amount of Synchronized Reserve provided shall be subtracted from its Normal Maximum Generation energy limit.

1.7.19A.01 Non-Synchronized Reserve.

(a) Non-Synchronized Reserve shall be supplied from generation resources and/or Demand Resources located within the metered boundaries of the PJM Region. Generating Market Buyers and Market Sellers offering Non-Synchronized Reserve shall comply with applicable standards and requirements for Non-Synchronized Reserve capability and dispatch specified in the PJM Manuals.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone an amount of Non-Synchronized Reserve such that the sum of the Synchronized Reserve and Non-Synchronized Reserve meets the Primary Reserve objective for such Reserve Zone, as specified in the PJM Manuals.

(c) The Non-Synchronized Reserve capability of a generation resource and Demand Resource shall be the increase in energy output or load reduction achievable by the generation resource and Demand Resource within a continuous 10-minute period provided that the resource is not synchronized to the system at the initiation of the response.

1.7.19B Bilateral Transactions Regarding Regulation, Synchronized Reserve and Day-ahead Scheduling Reserves.

(a) In addition to transactions in the Regulation market, Synchronized Reserve market, and Day-ahead Scheduling Reserves Market, Market Participants may enter into bilateral contracts for the purchase or sale of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from each other or any other entity. Such bilateral contracts shall be for the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its eMarket tools.

(b) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to a Market Participant in the PJM Region, title to the product that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and any further transactions associated with such products or further sale of such Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves in the markets for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves, respectively, shall be transacted by the buyer under the bilateral contract. In no event shall the purchase and sale of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves between Market Participants under a bilateral contract constitute a transaction in PJM's markets for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves, or otherwise be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

(c) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the amounts of such reported transactions to amounts reflecting the expected requirements for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves of the buyer pursuant to such bilateral contracts.

(d) All payments and related charges for the Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by 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 a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

(e) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any purchases by the seller under the bilateral contract in the markets for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves used to meet the bilateral contract seller's obligation to deliver Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new eMarket reporting by the Market Participant and (ii) terminate all of the Market Participant's reporting of eMarkets schedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the reported eMarkets schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection.

(f) Market Participants shall purchase Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves from PJM's markets for Regulation, Synchronized Reserve, Day-ahead Scheduling Reserves, in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason, with respect to all bilateral transactions that contemplate the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from a Market Participant.

1.7.20 Communication and Operating Requirements.

(a) Market Participants. Each Market Participant shall have, or shall arrange to have, its transactions in the PJM Interchange Energy Market subject to control by a Market Operations Center, with staffing and communications systems capable of real-time communication with the Office of the Interconnection during normal and Emergency conditions and of control of the Market Participant's relevant load or facilities sufficient to meet the requirements of the Market

Participant's transactions with the PJM Interchange Energy Market, including but not limited to the following requirements as applicable.

(b) Market Sellers selling from generation resources and/or Demand Resources within the PJM Region shall: report to the Office of the Interconnection sources of energy available for operation; supply to the Office of the Interconnection all applicable Offer Data; report to the Office of the Interconnection generation resources and Demand Resources that are self-scheduled; with respect to generation resources, report to the Office of the Interconnection bilateral sales transactions to buyers not within the PJM Region; confirm to the Office of the Interconnection bilateral sales to Market Buyers within the PJM Region; respond to the Office of the Interconnection's directives to start, shutdown or change output levels of generation units, or change scheduled voltages or reactive output levels of generation units, or reduce load from Demand Resources; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, generating equipment and Demand Resources are operated with control equipment functioning as specified in the PJM Manuals.

(c) Market Sellers selling from generation resources outside the PJM Region shall: provide to the Office of the Interconnection all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to Office of the Interconnection directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the Market Seller's Control Area.

(d) Market Participants that are Load Serving Entities or purchasing on behalf of Load Serving Entities shall: respond to Office of the Interconnection directives for load management steps; report to the Office of the Interconnection Generation Capacity Resources to satisfy capacity obligations that are available for pool operation; report to the Office of the Interconnection all bilateral purchase transactions; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(e) Market Participants that are not Load Serving Entities or purchasing on behalf of Load Serving Entities shall: provide to the Office of the Interconnection requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the PJM Interchange Energy Market, along with Dispatch Rate levels above which it does not desire to purchase; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(f) Economic Load Response Participants are responsible for maintaining demand reduction information, including the amount and price at which demand may be reduced. The Economic Load Response Participant shall provide this information to the Office of the Interconnection by posting it on the Load Response Program Registration link of the PJM website as required by the PJM Manuals. The Economic Load Response Participant shall notify the Office of the Interconnection of a demand reduction concurrent with, or prior to, the beginning of such demand reduction in accordance with the PJM Manuals. In the event that an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the

Interconnection of a change in its operations or the operations of the end-use customer that would affect a relevant Customer Baseline Load as required by the PJM Manuals.

(g) PRD Providers shall be responsible for ensuring automated reductions to their Price Responsive Demand in response to price in accordance with their PRD Curves submitted to the Office of the Interconnection.

1.10 Scheduling.

1.10.1 General.

(a) The Office of the Interconnection shall administer scheduling processes to implement a Day-ahead Energy Market and a Real-time Energy Market. PJMSettlement shall be the Counterparty to the purchases and sales of energy that clear the Day-ahead Energy Market and the Real-time Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a Generating Market Buyer's self-schedule or self-supply of its generation resources up to that Generating Market Buyer's Equivalent Load.

(b) The Day-ahead Energy Market shall enable Market Participants to purchase and sell energy through the PJM Interchange Energy Market at Day-ahead Prices and enable Transmission Customers to reserve transmission service with Transmission Congestion Charges and Transmission Loss Charges based on locational differences in Day-ahead Prices. Up-To Congestion transactions submitted in the Day-ahead Energy Market shall not require transmission service and Transmission Customers shall not reserve transmission service for such transactions. Market Participants whose purchases and sales, and Transmission Customers whose transmission uses are scheduled in the Day-ahead Energy Market, shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, at the applicable Day-ahead Prices for the amounts scheduled.

(c) In the Real-time Energy Market, Market Participants that deviate from the amounts of energy purchases or sales, or Transmission Customers that deviate from the transmission uses, scheduled in the Day-ahead Energy Market shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling shall be conducted as specified below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM Manuals.

1.10.1A Day-ahead Energy Market Scheduling.

The following actions shall occur not later than 12:00 noon on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the Office of the Interconnection in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Schedule.

(a) Each Market Participant may submit to the Office of the Interconnection specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the PJM Manuals. Each Market Buyer shall inform the Office of the Interconnection of the prices, if any, at which it desires not to include its load in the Day-ahead Energy Market rather than pay the Day-ahead Price. PRD Providers that have committed Price Responsive Demand in accordance with the Reliability Assurance Agreement shall submit to the Office of the Interconnection, in accordance with procedures specified in the PJM Manuals, any desired updates to their previously submitted PRD Curves, provided that such updates are consistent with their Price Responsive Demand commitments, and provided further that PRD Providers that are not Load-Serving Entities for the Price Responsive Demand load at issue may only submit PRD Curves for the Real-time Energy Market. Price Responsive Demand that has been committed in accordance with the Reliability Assurance Agreement shall be presumed available for the next Operating Day in accordance with the most recently submitted PRD Curve unless the PRD Curve is updated to indicate otherwise. PRD Providers may also submit PRD Curves for any Price Responsive Demand that is not committed in accordance with the Reliability Assurance Agreement; provided that PRD Providers that are not Load-Serving Entities for the Price Responsive Demand load at issue may only submit PRD Curves for the Real-time Energy Market. All PRD Curves shall be on a PRD Substation basis, and shall specify the maximum time period required to implement load reductions.

(b) Each Generating Market Buyer shall submit to the Office of the Interconnection: (i) hourly schedules for resource increments, including hydropower units, self-scheduled by the Market Buyer to meet its Equivalent Load; and (ii) the Dispatch Rate at which each such self-scheduled resource will disconnect or reduce output, or confirmation of the Market Buyer's intent not to reduce output.

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

Office of the Interconnection if the parties to the transaction are not willing to incur Transmission Congestion Charges in the Real-time Energy Market in order to complete any such scheduled bilateral transaction. Scheduling of bilateral transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

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

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

iii) In addition to the foregoing schedules for bilateral transactions, Market Participants shall submit confirmations of each scheduled bilateral transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(d) Market Sellers wishing to sell into the Day-ahead Energy Market shall submit offers for the supply of energy (including energy from hydropower units), demand reductions, Regulation, Operating Reserves or other services for the following Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Attachment DD of the PJM Tariff, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. *Any offer not designated as a Maximum Emergency Offer shall be considered available for scheduling and dispatch under both Emergency and non-Emergency conditions. Offers may only be designated as Maximum Emergency Offers to the extent that the Generation Capacity Resource falls into at least one of the following categories:*

i) Environmental limits. If the resource has a limit on its run hours imposed by a federal, state or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited to operating only during declared PJM capacity emergencies by a governmental authority.

ii) Fuel limits. If physical events beyond the control of the resource owner result in the temporary interruption of fuel supply and there is limited on-site fuel storage. A fuel supplier's exercise of a contractual right to interrupt supply or delivery

under an interruptible service agreement shall not qualify as an event beyond the control of the resource owner.

iii) Temporary emergency conditions at the unit. If temporary emergency physical conditions at the resource significantly limit its availability.

iv) Temporary megawatt additions. If a resource can provide additional megawatts on a temporary basis by oil topping, boiler over-pressure, or similar techniques and such megawatts are not ordinarily otherwise available.

The submission of offers for resource increments that have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, and PJM Manuals, as applicable. Energy offered from generation resources that have not cleared a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region. The foregoing offers:

i) Shall specify the Generation Capacity Resource or Demand Resource and energy or demand reduction amount, respectively, for each hour in the offer period, and the minimum run time for generation resources and minimum down time for Demand Resources;

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

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

iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;

v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with a second schedule applicable if accepted after the foregoing deadline;

vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer, which offer shall remain open through the Operating Day for which the offer is submitted;

vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day; and

viii) Shall not exceed an energy offer price of $1,000/megawatt-*hour for all generation resources and Demand Resources that have cleared a Base Residual Auction or an Incremental Auction.*

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation that shall specify the megawatt of Regulation being offered, which must equal or exceed 0.1 megawatts, the Regulation Zone for which such regulation is offered, the price of the capability offer in dollars per MW, the price of the performance offer in Dollars per change in MW, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the resource's opportunity costs. The total of the performance offer multiplied by the historical average mileage used in the market clearing plus the capability offer shall not exceed $100 per MWh in the case of Regulation offered for all Regulation Zones. In addition to any market-based offer for Regulation, the Market Seller also shall submit a cost-based offer. A cost-based offer must be in the form specified in the PJM Manuals and consist of the following components as well as any other components specified in the PJM Manuals:

i. The costs (in $/MW) of the fuel cost increase due to the heat rate increase resulting from operating a unit at lower megawatt output incurred from the provision of Regulation;

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

iii. An adder of up to $12.00 per megawatt of Regulation provided applied to the capability offer.

Qualified Regulation capability must satisfy the measurement and verification tests specified in the PJM Manuals.

(f) Each Market Seller owning or controlling the output of a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative shall submit a forecast of the availability of each such Generation Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with start-up and no-load fees, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours.

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

(h) The Office of the Interconnection shall post the total hourly loads scheduled in the Day-ahead Energy Market, as well as, its estimate of the combined hourly load of the Market Buyers for the next four days, and peak load forecasts for an additional three days.

(i) Except for Economic Load Response Participants, all Market Participants may submit Increment Bids and/or Decrement Bids that apply to the Day-ahead Energy Market only. Such bids must comply with the requirements set forth in the PJM Manuals and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-ahead Energy Market. The Office of the Interconnection may require that a market participant shall not submit in excess of 3000 bid/offer segments in the Day-ahead Energy Market, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to 10:00 a.m. EPT on the day that the Day-ahead Energy Market will clear. For purposes of this provision, a bid/offer segment is each pairing of price and megawatt quantity submitted as part of an Increment Bid or Decrement Bid.

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

(k) An Economic Load Response Participant that wishes to participate in the Day-ahead Energy Market by reducing demand shall submit an offer to reduce demand to the Office of the Interconnection. The offer must equal or exceed 0.1 megawatts, and the offer shall specify: (i) the amount of the offered curtailment in minimum increments of .1 megawatts: (ii) the Day-ahead Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, start-up costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum of number of contiguous hours for which the load reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs).

(l) Market Sellers owning or controlling the output of a Demand Resource that was committed in an FRR Capacity Plan, self-supplied or offered and cleared in the Base Residual Auction or one of the Incremental Auctions, or owning or controlling the output of an ILR resource which was certified as specified in Attachment DD of the PJM Tariff, may submit

demand reduction bids for the available load reduction capability of the Demand Resource or ILR resource. The submission of demand reduction bids for resource increments that have not cleared in the Base Residual Auction or in one of the Incremental Auctions, or for ILR resources that were not certified, or were not committed in an FRR Capacity Plan, shall be optional, but any such bids must contain the information specified in the PJM Economic Load Response Program to be included in such bids. A Demand Resource that was committed in an FRR Capacity Plan, self-supplied or offered and cleared in a Base Residual Auction or an Incremental Auction may submit a demand reduction bid in the Day-ahead Energy Market as specified in the Economic Load Response Program, provided however, that in the event of an Emergency, PJM shall require Demand Resources and ILR resources to reduce load notwithstanding that the Zonal LMP at the time such Emergency is declared is below the price identified in the demand reduction bid.

(m) Market Sellers that wish to make Day-ahead Scheduling Reserves Resources available to sell Day-ahead Scheduling Reserves shall submit offers, each of which must equal or exceed 0.1 megawatts, in the Day-ahead Scheduling Reserves Market specifying: 1) the price of the offer in dollars per megawatt hour; and 2) such other information specified by the Office of the Interconnection as may be necessary to determine any relevant opportunity costs for the resource(s). The foregoing notwithstanding, to qualify to submit offers pursuant to this section, the Day-ahead Scheduling Reserves Resources shall submit energy offers in the Day-ahead Energy Market including start-up and shut-down costs for generation resource and Demand Resources, respectively, and all generation resources that are capable of providing Day-ahead Scheduling Reserves that a particular resource can provide that service. The MW quantity of Day-ahead Scheduling Reserves that a particular resource can provide in a given hour will be determined based on the energy Offer Data submitted in the Day-ahead Energy Market, as detailed in the PJM Manuals.

1.10.2 Pool-scheduled Resources.

Pool-scheduled resources are those resources for which Market Participants submitted offers to sell energy in the Day-ahead Energy Market and offers to reduce demand in the Day-ahead Energy Market, which the Office of the Interconnection scheduled in the Day-ahead Energy Market as well as generators committed by the Office of the Interconnection subsequent to the Day-ahead Energy Market. Such resources shall be committed to provide energy in the real-time dispatch unless the schedules for such units are revised pursuant to Sections 1.10.9 or 1.11. Pool-scheduled resources shall be governed by the following principles and procedures.

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, start-up, no-load and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in Section 1.10.1A.

(b) A resource that is scheduled by a Market Participant to support a bilateral sale, or that is self-scheduled by a Generating Market Buyer, shall not be selected by the Office of the Interconnection as a pool-scheduled resource except in an Emergency.

(c) Market Sellers offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the Office of the Interconnection that is sufficient to enable the Office of the Interconnection to determine the available operating hours of such facilities.

(d) The Market Seller of a resource selected as a pool-scheduled resource shall receive payments or credits for energy, demand reductions or related services, or for start-up and no-load fees, from the Office of the Interconnection on behalf of the Market Buyers in accordance with Section 3 of this Schedule 1. Alternatively, the Market Seller shall receive, in lieu of start-up and no-load fees, its actual costs incurred, if any, up to a cap of the resource's start-up cost, if the Office of the Interconnection cancels its selection of the resource as a pool-scheduled resource and so notifies the Market Seller before the resource is synchronized.

(e) Market Participants shall make available their pool-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone.

(f) Economic Load Response Participants offering to reduce demand shall specify: (i) the amount of the offered curtailment, which offer must equal or exceed 0.1 megawatts, in minimum increments of .1 megawatts; (ii) the real-time Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, shut-down costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum number of contiguous hours for which the load reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Real-time Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs). Economic Load Response Participants offering to reduce demand shall also indicate the hours that the demand reduction is not available.

1.10.3 Self-scheduled Resources.

Self-scheduled resources shall be governed by the following principles and procedures.

(a) Each Generating Market Buyer shall use all reasonable efforts, consistent with Good Utility Practice, not to self-schedule resources in excess of its Equivalent Load.

(b) The offered prices of resources that are self-scheduled, or otherwise not following the dispatch orders of the Office of the Interconnection, shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.

(c) Market Participants shall make available their self-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone, by submitting an offer as to such resources.

(d) A Market Participant self-scheduling a resource in the Day-ahead Energy Market that does not deliver the energy in the Real-time Energy Market, shall replace the energy not

delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

1.10.4 Capacity Resources.

(a) A Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that is selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection. Such a Generation Capacity Resource that does not deliver energy as scheduled shall be deemed to have experienced a Generator Forced Outage to the extent of such energy not delivered. A Market Participant offering such Generation Capacity Resource in the Day-ahead Energy Market shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Energy from a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that has not been scheduled in the Day-ahead Energy Market may be sold on a bilateral basis by the Market Seller, may be self-scheduled, or may be offered for dispatch during the Operating Day in accordance with the procedures specified in this Schedule. Such a Generation Capacity Resource that has not been scheduled in the Day-ahead Energy Market and that has been sold on a bilateral basis must be made available upon request to the Office of the Interconnection for scheduling and dispatch during the Operating Day if the

Office of the Interconnection declares a Maximum Generation Emergency. Any such resource so scheduled and dispatched shall receive the applicable Real-time Price for energy delivered.

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

1.10.5 External Resources.

(a) External Resources may submit offers to the PJM Interchange Energy Market, in accordance with the day-ahead and real-time scheduling processes specified above. An External Resource selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection, and except as specified below shall be compensated on the same basis as other pool-scheduled resources. External Resources that are not capable of dynamic dispatch shall, if selected by the Office of the Interconnection on the basis of the Market Seller's Offer Data, be block loaded on an hourly scheduled basis. Market Sellers shall offer External Resources to the PJM Interchange Energy Market on either a resource-specific or an aggregated resource basis. A Market Participant whose pool-scheduled resource does not deliver the energy scheduled in the Day-ahead Energy Market shall replace such energy not delivered as scheduled in the Day-ahead Energy Market with energy from the PJM Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Offers for External Resources from an aggregation of two or more generating units shall so indicate, and shall specify, in accordance with the Offer Data requirements specified by the Office of the Interconnection: (i) energy prices; (ii) hours of energy availability; (iii) a minimum dispatch level; (iv) a maximum dispatch level; and (v) unless such information has previously been made available to the Office of the Interconnection, sufficient information, as specified in the PJM Manuals, to enable the Office of the Interconnection to model the flow into the PJM Region of any energy from the External Resources scheduled in accordance with the Offer Data.

(c) Offers for External Resources on a resource-specific basis shall specify the resource being offered, along with the information specified in the Offer Data as applicable.

1.10.6 External Market Buyers.

(a) Deliveries to an External Market Buyer not subject to dynamic dispatch by the Office of the Interconnection shall be delivered on a block loaded basis to the bus or buses at the electrical boundaries of the PJM Region, or in such area with respect to an External Market Buyer's load within such area not served by Network Service, at which the energy is delivered to or for the External Market Buyer. External Market Buyers shall be charged (which charge may be positive or negative) at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing bus or buses.

(b) An External Market Buyer's hourly schedules for energy purchased from the PJM Interchange Energy Market shall conform to the ramping and other applicable requirements of the interconnection agreement between the PJM Region and the Control Area to which, whether as an intermediate or final point of delivery, the purchased energy will initially be delivered.

(c) The Office of the Interconnection shall curtail deliveries to an External Market Buyer if necessary to maintain appropriate reserve levels for a Control Zone as defined in the PJM Manuals, or to avoid shedding load in such Control Zone.

1.10.6A Transmission Loading Relief Customers.

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

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

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

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

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

1.10.7 Bilateral Transactions.

Bilateral transactions as to which the parties have notified the Office of the Interconnection by the deadline specified in Section 1.10.1A that they elect not to be included in the Day-ahead Energy Market and that they are not willing to incur Transmission Congestion Charges in the Real-time Energy Market shall be curtailed by the Office of the Interconnection as necessary to reduce or alleviate transmission congestion. Bilateral transactions that were not included in the Day-ahead Energy Market and that are willing to incur congestion charges and bilateral transactions that were accepted in the Day-ahead Energy Market shall continue to be implemented during periods of congestion, except as may be necessary to respond to Emergencies.

1.10.8 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers and PRD Curves properly submitted by Load Serving Entities for the Price Responsive Demand loads they serve; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv) the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall

report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) Not earlier than 4:00 p.m. of the day before each Operating Day, or such other deadline as may be specified by the Office of the Interconnection in the PJM Manuals, the Office of the Interconnection shall: (i) post the aggregate Day-ahead Energy Market results; (ii) post the Day-ahead Prices; and (iii) inform the Market Sellers, Market Buyers, and Economic Load Response Participants of their scheduled injections, withdrawals, and demand reductions respectively.

(c) Following posting of the information specified in Section 1.10.8(b), the Office of the Interconnection shall revise its schedule of generation resources to reflect updated projections of load, conditions affecting electric system operations in the PJM Region, the availability of and constraints on limited energy and other resources, transmission constraints, and other relevant factors.

(d) Market Buyers shall pay PJMSettlement and Market Sellers shall be paid by PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the offer that set the Day-ahead Price is positive. Market Buyers shall be paid by PJMSettlement and Market Sellers shall pay PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the offer that set the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Section 3.3A of this Schedule.

(e) If the Office of the Interconnection discovers an error in prices and/or cleared quantities in the Day-ahead Energy Market, Real-time Energy Market, Ancillary Services Markets or Day Ahead Scheduling Reserve Market after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 12:00 p.m. of the second business day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the second business day following the initial publication of the results for the Day-ahead Scheduling Reserve Market and Day-ahead Energy Market.

After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the fifth business day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the fifth business day following the initial publication of the results in the Day-ahead Scheduling Reserve Market and the Day-ahead Energy Market. Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating Day for the Ancillary Services Markets, Day-ahead Energy Market and Real-time Energy Market, and no later than 5:00 p.m. of the tenth calendar day following the initial publication of the results in the Day-ahead Scheduling Reserve Market. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final.

Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced market results are under publicly noticed review by the FERC.

(f) Consistent with Section 18.17.1 of the PJM Operating Agreement, and notwithstanding anything to the contrary in the Operating Agreement or in the PJM Tariff, to allow the tracking of Market Participants' non-aggregated bids and offers over time as required by FERC Order No. 719, the Office of the Interconnection shall post on its Web site the non-aggregated bid data and Offer Data submitted by Market Participants (for participation in the PJM Interchange Energy Market) approximately four months after the bid or offer was submitted to the Office of the Interconnection.

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, a generation rebidding period shall exist from 4:00 p.m. to 6:00 p.m. on the day before each Operating Day. During the rebidding period, Market Participants may submit revisions to generation Offer Data for any generation resource that was not selected as a pool-scheduled resource in the Day-ahead Energy Market. Adjustments to Day-ahead Energy Markets shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 60 minutes prior to the hour in which the adjustment is to take effect, as follows:

i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;

ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or

iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or

iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any start-up fee.

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

(d) An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase in the Day-ahead Energy Market by notifying the Office of the Interconnection of the adjustment in deliveries not later than 60 minutes prior to the hour in which the adjustment is to take effect, but any such adjustment shall not affect the obligation of the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(e) For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section 1.10, the Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules for the hour.

1.11 Dispatch.

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

1.11.1 Resource Output.

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

1.11.2 Operating Basis.

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

1.11.3 Pool-dispatched Resources.

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

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

1.11.3A Maximum Generation Emergency.

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

1.11.4 Regulation.

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

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

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

1.11.4A Synchronized Reserve.

(a) A Market Buyer may satisfy its Synchronized Reserve -Oobligation from its own generation resources and/or Demand Resources capable of providing Synchronized Reserve, by contractual arrangements with other Market Participants able to provide Synchronized Reserve,

or by purchases from the PJM Synchronized Reserve Market at the rates set forth in Section 3.2.3A. PJMSettlement shall be the Counterparty to the purchases and sales of Synchronized Reserve in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Synchronized Reserve Obligation.

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

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

1.11.4B Non-Synchronized Reserve.

(a) A Market Buyer may satisfy its Non-Synchronized Reserve Obligation from its own generation resources and/or Demand Resources capable of providing Non-Synchronized Reserve, by contractual arrangements with other Market Participants able to provide Non-Synchronized Reserve, or by purchases from the PJM Non-Synchronized Reserve Market at the rates set forth in Section 3.2.3A.001.

(b) The Office of the Interconnection shall obtain Non-Synchronized Reserve from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Demand Resources as needed to ensure the Primary Reserve requirement of each Reserve Zone of the PJM Region not otherwise satisfied by the Market Buyers. Resources offering to sell Non-Synchronized Reserve shall be selected to provide Non-Synchronized Reserve on the basis of each generation resource's and/or Demand Resource's estimated unit specific opportunity cost of the resource providing Non-Synchronized Reserve, and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Synchronized Reserve and other ancillary services. Estimated unit specific opportunity costs for generation resources shall be equal to the 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 Non-Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources will be zero.

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

1.11.5 PJM Open Access Same-time Information System.

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

2.2 General.

The Office of the Interconnection shall determine the least cost security-constrained dispatch, which is the least costly means of serving load *and meeting reserve requirements* at different locations in the PJM Region based on actual operating conditions existing on the power grid (including transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6) and on the prices at which Market Sellers have offered to supply energy and offers by Economic Load Response Participants to reduce demand that qualify to set Locational Marginal Prices in the PJM Interchange Energy Market. Locational Marginal Prices for the generation and load busses in the PJM Region, including interconnections with other Control Areas, will be calculated based on the actual economic dispatch and the prices of energy and demand reduction offers. The process for the determination of Locational Marginal Prices shall be as follows:

(a) To determine actual operating conditions on the power grid in the PJM Region, the Office of the Interconnection shall use a computer model of the interconnected grid that uses available metered inputs regarding generator output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network. The computer model employed for this purpose, referred to as the State Estimator program, is a standard industry tool and is described in Section 2.3 below. It will be used to obtain information regarding the output of generation supplying energy to the PJM Region, loads at busses in the PJM Region, transmission losses, and power flows on binding transmission constraints for use in the calculation of Locational Marginal Prices. Additional information used in the calculation, including Dispatch Rates and real time schedules for external transactions between PJM and other Control Areas and dispatch and pricing information from entities with whom PJM has executed a joint operating agreement, will be obtained from the Office of the Interconnection's dispatchers.

(b) Using the prices at which energy is offered by Market Sellers and demand reductions are offered by Economic Load Response Participants to the PJM Interchange Energy Market, the Office of the Interconnection shall determine the offers of energy and demand reductions that will be considered in the calculation of Locational Marginal Prices. As described in Section 2.4 below, every qualified offer for demand reduction and of energy by a Market Seller from resources that are *dispatched by* the Office of the Interconnection will be utilized in the calculation of Locational Marginal Prices, including, without limitation, qualified offers from Economic Load Response Participants in either the Day-Ahead or Real-Time Energy Markets that satisfy the Net Benefits Test. Offers of *economic load response* from Demand Resources in the Real-time Energy Market will not be eligible to set Locational Marginal Prices, unless metered directly by the Office of the Interconnection. *Offers of Full Program Option resources in the Emergency Load Response Program are eligible to set real time Locational Marginal Prices when the Office of the Interconnection has implemented Emergency procedures and such resources are required to reduce demand in the PJM Region, so long as sufficient data is available to accurately model the resources.*

(c) Based on the system conditions on the PJM power grid, determined as described in (a), and the eligible energy and demand reduction offers, determined as described in (b), the

Office of the Interconnection shall determine the least costly means of obtaining energy to serve the next increment of load at each bus in the PJM Region, in the manner described in Section 2.5 below. The result of that calculation shall be a set of Locational Marginal Prices based on the system conditions at the time.

2.3 Determination of System Conditions Using the State Estimator.

Power system operations, including, but not limited to, the determination of the least costly means of serving load *and meeting reserve requirements*, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In calculating Locational Marginal Prices, the Office of the Interconnection shall obtain a complete and consistent description of conditions on the electric network in the PJM Region by using the most recent power flow solution produced by the State Estimator *program and utilized in the PJM dispatch algorithm*, which *State Estimator program* is also used by the Office of the Interconnection for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available real-time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at busses for which real-time information is unavailable. The Office of the Interconnection shall obtain a State Estimator solution every five minutes, which shall provide the megawatt output of generators and the loads at busses in the PJM Region, transmission line losses, and actual flows or loadings on constrained transmission facilities. External transactions between PJM and other Control Areas shall be included in the Locational Marginal Price calculation on the basis of the real time transaction schedules implemented by the Office of the Interconnection's dispatcher.

2.4 Determination of Energy Offers Used in Calculating Real-time Prices.

(a) During the Operating Day, real-time Locational Marginal Prices derived in accordance with this Section shall be determined every five minutes and integrated hourly values of such determinations shall be the basis of sales and purchases of energy in the Real-time Energy Market and of Transmission Congestion Charges under the PJM Tariff not covered by the Day-ahead Energy Market.

(b) To determine the energy offers submitted to the PJM Interchange Energy Market that shall be used during the Operating Day to calculate the Real-time Prices, the Office of the Interconnection shall determine *the applicable marginal energy offer of the* resources *being dispatched by the Office of the Interconnection*. A resource shall be included in the calculation of Real-time Prices if the applicable *marginal energy offer of the* resource *being dispatched by the Office of the Interconnection* is less than or equal to the Dispatch Rate for the area of the PJM Region in which the resource is located.

(c) In determining whether a resource satisfies the condition described in (b), the Office of the Interconnection will determine the *applicable marginal* energy offer by comparing the *requested* megawatt output of the resource with the Market Seller's offer price curve. *T*he *applicable marginal* energy offer used in the calculation of Real-time Prices shall not exceed the applicable Dispatch Rate. Units that must be run for local area protection shall not be considered in the calculation of Real-time Prices.

2.5 Calculation of Real-time Prices.

(a) The Office of the Interconnection shall determine the least costly means of obtaining energy to serve the next increment of load (taking account of any applicable and available load reductions indicated on PRD Curves properly submitted by any PRD Provider) at each bus in the PJM Region represented in the State Estimator and each Interface Pricing Point between PJM and an adjacent Control Area, based on the system conditions described by the most recent power flow solution produced by the State Estimator program *and utilized in the PJM dispatch algorithm* and the energy offers that are the basis for the Day-ahead Energy Market, or that are determined to be eligible for consideration under Section 2.4 in connection with the real-time dispatch, as applicable. This calculation shall be made by applying *a real-time joint optimization of energy and reserves*, given actual system conditions, a set of energy offers, *a set of reserve offers, a set of Reserve Penalty Factors,* and any binding transmission constraints that may exist. In performing this calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a generation resource or decrease an increment of energy being consumed by a Demand Resource, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses. *The real-time Locational Marginal Prices at a bus shall be determined through the joint optimization based on the lowest marginal cost to serve the next increment of load at the bus taking into account the applicable reserve requirements, unit resource constraints, transmission constraints and marginal loss impact.*

(*b) If all reserve requirements in every modeled Reserve Zone can be met at prices less than or equal to the Reserve Penalty Factors for both the Synchronized Reserves and Non-synchronized Reserves, real-time Locational Marginal Prices shall be calculated as described in Section 2.5(a) above and no Reserve Penalty Factor shall apply beyond the normal lost opportunity costs incurred by the reserve requirements. When a reserve requirement cannot be met at a price less than or equal to the Reserve Penalty Factors associated with a Reserve Zone, the real-time Locational Marginal Prices shall be calculated by incorporating the applicable Reserve Penalty Factor for the deficient reserve product as the lost opportunity cost impact of the deficient reserve requirement, and the components of Locational Marginal Prices referenced in Section 2.5(a) above shall be calculated accordingly.*

(c) If the Office of the Interconnection has initiated in a Reserve Zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, Locational Marginal Prices for that Reserve Zone will be calculated including the Reserve Penalty Factors of all reserve products in that Reserve Zone.

(*d*) During the Operating Day, the calculation set forth in (a) shall be performed every five minutes, using the Office of the Interconnection's Locational Marginal Price program, producing a set of Real-time Prices based on system conditions during the preceding interval. The prices produced at five-minute intervals during an hour will be integrated to determine the Real-time Prices for that hour.

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 (g) of this section;the amounts, if any, described in subsection (e) of this section; and (iii) the Internal Market Buyer's pro rata share of any performance credits paid to regulating resources calculated in accordance with subsection (f) 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 such that the calculated credit for each increment of Regulation provided by each resource shall be the Regulation market-clearing price.

(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 (f) 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 from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.3.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation *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 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.

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

(e) 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.

(f) 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 (f) 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 capacity Regulation market-clearing price.

(g) 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.

(h) 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.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to section 1.10.1A(e) of this Schedule. A Regulation supplier fails the three-pivotal supplier test in any hour in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

(b) For the purposes of conducting the three-pivotal supplier test pursuant to this section, the following applies:

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region for which the 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.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Section 3.2.3A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the Day-ahead Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load fees and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead

Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve credits, identified as RA Credits for Reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

(c) The sum of the foregoing credits calculated in accordance with Section 3.2.3(b) plus any unallocated charges from Section 3.2.3(h) and 5.1.7 and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of Operating Reserves in the Day-ahead Energy Market.

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following segments: 1) the greater of their day-ahead schedules or minimum run time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or minimum run time (minimum down time for Demand Resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time (minimum down time for Demand Resources) and Segment 2 will include the remainder of the contiguous hours when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

Credits received pursuant to this section shall be equal to the positive difference between a resource's total offered price for start-up (shutdown costs for Demand Resources) and no-load fees and energy, determined on the basis of the resource's scheduled output, and the total value of the resource's energy as determined by the Real-time Energy Market and the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for segment 2 shall exclude start up (shutdown costs for Demand Resources) costs for generation resources.

Except as provided in Section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to Section 3.2.3(b) plus the resource's opportunity cost and less any amounts credited for Synchronized Reserve in excess of the Synchronized Reserve offer plus the resource's opportunity cost and less any amounts credited for providing Reactive Services as specified in Section 3.2.3B, and less any amounts for Day-

ahead Scheduling Reserve in excess of the Day-ahead Scheduling Reserve offer plus the resource's opportunity cost, shall be credited to the Market Seller.

Synchronized Reserve, *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 {(LMPDMW - AG) x (URTLMP – UB)}, where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

AG equals the actual hourly integrated output of the unit;

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

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

where URTLMP - UB shall not be negative.

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

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the

level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described above for a steam unit or combined cycle unit operating in combined cycle mode.

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

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

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

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

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

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

(f-2) A Market Seller's hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Section 1.10.2(d) such cancellation fees to be applied to the Operating Day for which the

unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves, plus any redispatch costs incurred in accordance with section 10(a) of this Schedule, shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (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.

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 busses that define all interfaces or all hubs are located in the region. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by busses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed in accordance with the following provisions:

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive

values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of an Operating Reserve shortage in real-time or where PJM initiates the request for load reductions in real-time in order to avoid an Operating Reserve shortage.

(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 <= 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

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

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

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 <= 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 <= 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 n 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 to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve charges shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve charges shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to

maintain system reliability, the associated balancing Operating Reserve charges shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region. For the purposes of this section, the Western Region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, *DEOK* transmission Zones, and the Eastern Region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones. The regional balancing Operating Reserve rates shall be determined in accordance with the following provisions:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are

designated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

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

(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.

3.2.3A Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). An Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts if any, described in subsections (g), (h) and (i) of this section.

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

i) Credits for Synchronized Reserve provided by generation *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*; with the exception of those hours in which the Non-Synchronized Reserve Market Clearing Price for the applicable Reserve 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 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 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, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve requirement in a Reserve 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, but less than or equal to the sum of the Synchronized Reserve Penalty Factor and the Primary Reserve Penalty Factor for the Reserve Zone. If the Office of the Interconnection has initiated in a Reserve 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.*

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

i. $250/MWh for the 2011/2012 Delivery Year;

ii. $400/MWh for the 2012/2013 Delivery Year;

iii. $550/MWh for the 2013/2014 Delivery Year; and

iv. $850/MWh as of the 2014/2015 Delivery Year.

After June 1, 2014, 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 the 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 expected Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

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

(g) Charges for Tier 1 Synchronized Reserve will be allocated in proportion to the amount of Tier 1 Synchronized Reserve applied to each Synchronized Reserve Obligation. In the event Tier 1 Synchronized Reserve is provided by a Market Seller in excess of that Market Seller's Synchronized Reserve Obligation, the remainder of the Tier 1 Synchronized Reserve that is not utilized to fulfill the Seller's obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

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

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

(j) In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled by the owner to provide Tier 2 Synchronized Reserve fails to provide the assigned or self-scheduled amount of Synchronized Reserve in response to an actual Synchronized Reserve Event, *the 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 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 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 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 for the hour ("Non-Synchronized Reserve Obligation"). 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 (d) of this section, plus the amounts if any, described in paragraphs (g), (h) and (i) 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 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. Opportunity costs for Demand Resources to provide Non-Synchronized Reserves are zero.*

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve 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 serving the next increment of demand for Non-Synchronized Reserve in each Reserve Zone inclusive of opportunity costs associated with meeting the Primary Reserve requirement. When the Primary Reserve requirement in a Reserve

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 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.

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

i. $250/MWh for the 2011/2012 Delivery Year;

ii. $400/MWh for the 2012/2013 Delivery Year;

iii. $550/MWh for the 2013/2014 Delivery Year; and

iv. $850/MWh as of the 2014/2015 Delivery Year.

After June 1, 2014, 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 solely for the purpose of providing Non-Synchronized Reserves shall be equal to the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Non-Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. The opportunity costs for a Demand Resource shall be zero.

(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 difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the generation resource) in the PJM Interchange Energy Market. The opportunity costs for a Demand Resource shall be zero.

(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 or a Demand Resource, except for Batch Load Demand Resources covered by Section 3.2.3A(1), 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.

(h) 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 Non-Synchronized Reserve fails to provide the assigned or self-scheduled 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.

(i) 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 megawattts in its offer at the start of a Non-Synchronized Reserve Event shall be the difference between (i) the Batch Load Demand Resource's consumption at the end of the Non-Synchronized Reserve Event and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the end of the Non-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 Non-Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.

3.2.3A.01 Day-ahead Scheduling Reserves.

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

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

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

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

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

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

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

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

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

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

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit hourly in an amount equal to {(LMPDMW - AG) x (URTLMP - UB)}

where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

AG equals the actual hourly integrated output of the unit;

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

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

where URTLMP - UB shall not be negative.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

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

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

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

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

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

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

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to Section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit hourly in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual hourly integrated output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

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

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

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c)

hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generating unit's bus, (C) the generating unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generating resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generating unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsecton (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on

such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

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

3.2.5 Transmission Loss Charges.

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

3.2.6 Emergency Energy.

(a) *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.

3.3 Market Sellers.

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

3.3.1 Spot Market Energy Charges.

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

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

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

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

3.3.2 Regulation.

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

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

3.3.3 Operating Reserves.

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

3.3.4 Emergency Energy.

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

3.3.5 Synchronized Reserve.

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

3.*3.5A Non-Synchronized Reserve.*

Each Market Seller that is also an Internal Market Buyer shall have an hourly Non-Synchronized Reserve objective and shall be credited or charged in connection therewith as specified in Section 3.2.3A.001(a). All other Market Sellers supplying Non-Synchronized Reserve at the direction of the Office of the Interconnection shall be credited for each increment of such Synchronized Reserve at the price specified in Section 3.2.3A.001(b), as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

3.3.6 Billing.

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

6A [Reserved for Future Use]

6A.1 [Reserved For Future Use]

6A.2 [Reserved for Future Use]

6A.3 [Reserved for Future Use]

PJM EMERGENCY LOAD RESPONSE PROGRAM

Emergency Load Response Program

The Emergency Load Response Program is designed to provide a method by which end-use customers may be compensated by PJM for reducing load during an emergency event. As used in the Emergency Load Response Program, the term "end-use customer" refers to an individual location or aggregation of locations that consume electricity as identified by a unique electric distribution company account number. There are two options for participation in the Emergency Load Response Program:

- Full Program Option

  Participants in the Full Program Option receive, pursuant to Attachment DD of the Tariff and as applicable, (i) an energy payment for load reductions during an emergency event, and (ii) a capacity payment for load reductions during an emergency event measured as set forth in the Reporting and Compliance provisions below.

- Energy Only Option

  Participants in the Energy Only Option receive only an energy payment for load reductions during an emergency event.

Participant Qualifications

Two primary types of distributed resources are candidates to participate in either of the two options provided by the Emergency Load Response Program:

On-Site Generators

These generators (including Behind The Meter Generation) can be either synchronized or non-synchronized to the grid. Capacity Resources are not eligible for compensation under this program. Injections into the grid by local generators also will not be eligible for compensation under this program.

Load Reductions

A participant that has the ability to reduce a measurable and verifiable portion of its load, as metered on an EDC account basis.

PJM membership is required to participate in either of the two options provided by the Emergency Load Response Program. Members or Special Members may participate in the Emergency Load Response Program by complying with all of the requirements of the applicable Relevant Electric Retail Regulatory Authority and all other applicable federal, state and local regulatory entities together with the Emergency Load Response provisions herein, including, but

not limited to, the Registration section. Special membership provisions have been established for program participants in the Energy Only Option, as described below. The special membership provisions shall not apply to program participants in the Full Program Option. Any existing PJM Member may act as a third party for non-members, in which case the third party will be referred to as the Curtailment Service Provider (CSP). All payments are made to the PJM Member. Participants must become signatories to the PJM Operating Agreement, as described in the ***PJM Manual for Administrative Services for the Operating Agreement of the PJM Interconnection, L.L.C***. However, for special members the $5,000 annual membership fee, the $1,500 application fee, and liability for Member defaults are waived, along with the following other modifications:

Special Members are limited to be PJM market sellers;
Voting privileges and sector designation are waived;
Thirty day notice for waiting period is waived;
Requirement for 24/7 control center coverage is waived;
No PJM-supported user group capability is permitted.

To participate in either of the two options provided by the Emergency Load Response Program, the distributed resource must:

Be capable of reducing at least 100 kW of load
Be capable of receiving PJM notification to participate during emergency conditions.

Metering Requirements

The Curtailment Service Provider is responsible to ensure that the Emergency Load Response Program Participants have metering equipment that provides integrated hourly kWh values on an electric distribution company account basis. The metering equipment shall either meet the electric distribution company requirements for accuracy or have a maximum error of two percent over the full range of the metering equipment (including Potential Transformers and Current Transformers) and the metering equipment and associated data shall meet the requirements set forth herein and in the PJM Manuals. The Emergency Load Response Participant must meter reductions in demand by using either of the following two methods:

a) Using metering equipment that is capable of recording integrated hourly values for generation running to serve local load (net of that used by the generator); or

b) Using metering equipment that provides actual load change by measuring actual load before and after the reduction request, such that there is a valid integrated hourly value for the hour prior to the event and each hour during the event. This value cannot be estimated nor can it be averaged over some historical period. This load will be metered on an electric distribution company account basis.

Metered load reductions will be adjusted up to consider transmission and distribution losses as submitted by the Curtailment Service Provider and verified by PJM with the electric distribution company.

The installed metering equipment must be one of the following:

a) Metering equipment used for retail electric service;

b) Customer-owned metering equipment or metering equipment acquired by the Curtailment Service Provider, approved by PJM, that is read electronically by PJM, in accordance with the requirements herein and in the PJM Manuals; or

c) Customer-owned metering equipment or metering equipment acquired by the Curtailment Service Provider, approved by PJM, that is read by the customer (or the Curtailment Service Provider), and such readings are then forwarded to PJM, in accordance with the requirements set forth herein and in the PJM Manuals.

Nothing herein changes the existence of one recognized meter by the state commissions as the official billing meter for recording consumption.

Registration

1. Participants must complete the PJM Emergency Load Response Program Registration Form ("Emergency Registration Form") that is posted on the PJM website (www.pjm.com)for each end-use customer, or aggregation of end-use customers, pursuant to the requirements set forth in the PJM Manuals. Because of the required electric distribution company and Load Serving Entity ten business day review period, as described herein, Participants should submit completed PJM Emergency Load Response Program Registration Forms to the Office of the Interconnection no later than one day before the tenth business day preceding the relevant Delivery Year. All registrations that have not been approved on or before May 31st preceding the relevant Delivery Year shall be rejected by the Office of the Interconnection. To the extent that a completed PJM Emergency Load Response Program Registration Form is submitted to the Office of the Interconnection prior to one day before the tenth business day preceding the relevant Delivery Year and such registration is rejected by the electric distribution company or Load Serving Entity or the Office of the Interconnection because of incorrect data on the PJM Emergency Load Response Program Registration Form, such registration may be resubmitted by the participant before May 31st preceding the relevant Delivery Year, but such registration will be rejected by the Office of the Interconnection unless the electric distribution company or Load Serving Entity has verified the registration on or before May 31st preceding the relevant Delivery Year. Incomplete PJM Emergency Load Response Program Registration Forms will be rejected by the Office of the Interconnection; participants may not resubmit registrations that were rejected for being incomplete unless participants are able to do so no later than one day before the tenth business day preceding the relevant Delivery Year. The following general steps will be followed:

2. For end-use customers of an electric distribution company that distributed more than 4 million MWh in the previous fiscal year:

a. The participant completes the Emergency Registration Form located on the PJM website. PJM reviews the application and ensures that the qualifications are met, including

verifying that the appropriate metering exists. After confirming that an entity has met all of the qualifications to be an Emergency Load Response Participant, PJM shall notify the appropriate Load Serving Entity and electric distribution company of an Emergency Load Response Participant's registration and request verification as to whether the load that may be reduced is under other contractual obligations or subject to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Emergency Load Response Program pursuant to the process described below. The electric distribution company and Load Serving Entity have ten business days to respond. Other such contractual obligations may not preclude participation in the program, but may require special consideration by PJM such that appropriate settlements are made within the confines of such existing contracts. An electric distribution company or Load Serving Entity which seeks to assert that the laws or regulations of the Relevant Electric Retail Regulatory Authority prohibit or condition (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) an end-use customer's participation in PJM's Emergency Load Response Program shall provide to PJM, within the referenced ten business day review period, either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority prohibiting or conditioning the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law prohibiting or conditioning the end-use customer's participation.

i. If evidence provided by an electric distribution company or Load Serving Entity to the Office of the Interconnection indicates that a Relevant Electric Retail Regulatory Authority law or regulation prohibits or conditions (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation and is received by the Office of the Interconnection on or after the Interruptible Load for Reliability registration deadline established by the Office of the Interconnection for the next applicable Delivery Year, then the existing Emergency Load Response Participant's registration for Interruptible Load for Reliability (as defined in the Reliability Assurance Agreement) will remain in effect for the applicable Delivery Year. If evidence provided by an electric distribution company or Load Serving Entity to the Office of the Interconnection indicates that a Relevant Electric Retail Regulatory Authority law or regulation prohibits or conditions (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation and is received by the Office of the Interconnection before the Interruptible Load for Reliability registration deadline established by the Office of the Interconnection for the applicable Delivery Year, then the existing Emergency Load Response participant's registration for Interruptible Load for Reliability (as defined in the Reliability Assurance Agreement) participation shall be deemed to be terminated for the applicable Delivery Year.

ii. If evidence provided by an electric distribution company or Load Serving Entity to the Office of the Interconnection indicates that a Relevant Electric Retail Regulatory Authority law or regulation prohibits or conditions (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation and is received by the Office of the Interconnection on or after May 31st preceding the applicable Delivery Year, then the existing end-use customer's registration for Demand Resource (as defined in the Reliability Assurance Agreement) will remain in effect for the applicable Delivery Year. If evidence provided by an electric distribution company or Load Serving Entity to the Office of the Interconnection indicates that a Relevant Electric Retail Regulatory Authority law or regulation prohibits or conditions (which condition the electric distribution company or Load Serving Entity asserts has not been satisfied) the end-use customer's participation and is received by the Office of the Interconnection before May 31st preceding the applicable Delivery Year and the Curtailment Service Provider does not provide supporting documentation to the Office of the Interconnection on or before May 31st preceding the applicable Delivery Year demonstrating that the Curtailment Service Provider had an executed contract with the end-use customer for Demand Resource participation before the date the Demand Resource cleared the applicable Reliability Pricing Model Auction, and that the date that the Demand Resource cleared the applicable Reliability Pricing Model Auction was prior to the effective date of the Relevant Electric Retail Regulatory Authority law or regulation prohibiting or conditioning the end-use customer's participation, then, unless the below exception applies, the existing end-use customer's registration for Demand Resource participation shall be deemed to be terminated for the applicable Delivery Year, and the Curtailment Service Provider will be subject to the Reliability Pricing Model provisions, as specified in Attachment DD of the PJM Tariff.

(1) Except that, pursuant to all other PJM Tariff and PJM Manual provisions, PJM will allow participation of all end-use customers registered by Curtailment Service Providers to fulfill Curtailment Service Providers' Demand Resource obligations that were cleared in the Reliability Pricing Model Auctions prior to August 28, 2009.

b. In the absence of a response from the electric distribution company or Load Serving Entity within the referenced ten business day review period, the Office of the Interconnection shall assume that the load to be reduced is not subject to other contractual obligations or to laws or regulations of the Relevant Electric Retail Regulatory Authority that prohibit or condition the end-use customer's participation in PJM's Emergency Load Response Program, and the Office of the Interconnection shall accept the registration, provided it meets all other Emergency Load Response Program requirements.

c. For those registrations terminated pursuant to this section, all Emergency Load Response Participant activity incurred prior to the termination date of the registration shall be settled by PJM in accordance with the terms and conditions contained in the PJM Tariff, PJM Operating Agreement and PJM Manuals.

3. For end-use customers of an electric distribution company that distributed 4 million MWh or less in the previous fiscal year:

a. The Participant completes the Emergency Registration Form located on the PJM website. PJM reviews the application and ensures that the qualifications are met, including verifying that the appropriate metering exists. After confirming that an entity has met all of the qualifications to be an Emergency Load Response Participant, PJM shall notify the appropriate Load Serving Entity and electric distribution company of an Emergency Load Response Participant's registration and request verification as to whether the load that may be reduced is under other contractual obligations and is permitted to participate by the Relevant Electric Retail Regulatory Authority pursuant to the process described below. The electric distribution company and Load Serving Entity have ten business days to respond. Other such contractual obligations may not preclude participation in the program, but may require special consideration by PJM such that appropriate settlements are made within the confines of such existing contracts. If the electric distribution company or Load Serving Entity verifies that the load that may be reduced is permitted or conditionally permitted (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) to participate in the Emergency Load Response Program, then the electric distribution company or Load Serving Entity must provide to the Office of the Interconnection within the referenced ten business day review period either: (a) an order, resolution or ordinance of the Relevant Electric Retail Regulatory Authority permitting or conditionally permitting the end-use customer's participation, (b) an opinion of the Relevant Electric Retail Regulatory Authority's legal counsel attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation, or (c) an opinion of the state Attorney General, on behalf of the Relevant Electric Retail Regulatory Authority, attesting to the existence of a regulation or law permitting or conditionally permitting the end-use customer's participation.

i. If the electric distribution company or Load Serving Entity denies the Interruptible Load for Reliability (as defined in the Reliability Assurance Agreement) registration before the Interruptible Load for Reliability registration deadline as established by the Office of the Interconnection for the applicable Delivery Year because the electric distribution company or Load Serving Entity asserts that the Relevant Electric Retail Regulatory Authority has not granted permission or conditional permission for the end-use customer's participation or the electric distribution company or Load Serving Entity asserts that the end-use customer has not satisfied conditional permission requirements, then the existing Emergency Load Response Participant's registration for Interruptible Load for Reliability participation shall be deemed to be terminated for the applicable Delivery Year. If it is able to do so in compliance with all Emergency Load Response Program requirements, including the registration requirements,

the participant may submit a new registration to the Office of the Interconnection for consideration if a prior registration has been rejected pursuant to the terms of the Emergency Load Response Program provisions.

ii. If the electric distribution company or Load Serving Entity denies the end-use customer's Demand Resource (as defined in the Reliability Assurance Agreement) registration on or before May 31st preceding the applicable Delivery Year and the Curtailment Service Provider does not provide the above referenced Relevant Electric Retail Regulatory Authority evidence to the Office of the Interconnection on or before May 31st preceding the applicable Delivery Year demonstrating that the Curtailment Service Provider had Relevant Electric Retail Regulatory Authority permission or conditional permission (which condition the electric distribution company or Load Serving Entity asserts has been satisfied) for the end-use customer's participation and an executed contract with the end-use customer Demand Resource before the date the Demand Resource cleared the applicable Reliability Pricing Model Auction then, unless the below exception applies, the existing end-use customer's registration for Demand Resource registration for Demand Resource participation shall be deemed to be terminated for the applicable Delivery Year and the Curtailment Service Provider will be subject to the Reliability Pricing Model provisions, as specified in Attachment DD of the PJM Tariff.

(1) Except that, pursuant to all other PJM Tariff and PJM Manual provisions, PJM will allow participation of all end-use customers registered by Curtailment Service Providers to fulfill Curtailment Service Providers' Demand Resource obligations that were cleared in the Reliability Pricing Model Auctions prior to August 28, 2009.

b. In the absence of a response from the electric distribution company or Load Serving Entity within the referenced ten business day review period, the Office of the Interconnection shall reject the registration. If it is able to do so in compliance with all of the Emergency Load Response Program requirements, including the registration section, the Emergency Load Response Participant may submit a new registration to the Office of the Interconnection for consideration if a prior registration has been rejected pursuant to the terms of the Emergency Load Response Program provisions.

c. For those registrations terminated pursuant to this section, all Emergency Load Response participant activity incurred prior to the termination date of the registration shall be settled by PJMSettlement in accordance with the terms and conditions contained in the PJM Tariff, PJM Operating Agreement and PJM Manuals.

4. PJM informs the requesting participant of acceptance into the program and notifies the appropriate Load Serving Entity and electric distribution company of the requesting participant's acceptance into the program, or notifies the requesting participant and appropriate Load Serving

Entity and electric distribution company of PJM's rejection of the requesting participant's registration.

5. Any end-use customer intending to run distributed generating units in support of local load for the purpose of participating in this program must represent in writing to PJM that it holds all applicable environmental and use permits for running those generators. Continuing participation in this program will be deemed as a continuing representation by the owner that each time its distributed generating unit is run in accordance with this program, it is being run in compliance with all applicable permits, including any emissions, run-time limit or other constraint on plant operations that may be imposed by such permits.

Emergency Load Response Registrations in Effect as of August 28, 2009

All existing Emergency Load Response Participants' registrations submitted to PJM prior to August 28, 2009 (the effective date of *Wholesale Competition in Regions with Organized Electric Markets*, Order 719-A, 128 FERC ¶ 61,059 (2009) ("Order 719-A")) for Load Management participation in the 2009/2010 Delivery Year will remain effective for that Delivery Year.

Emergency Operations

PJM will initiate the request for load reduction following the declaration of Maximum Emergency Generation and prior to the implementation of Load Management Steps 1 and 2. (Implementation of the Emergency Load Response Program can be used for regional emergencies.) It is implemented whenever generation is needed that is greater than the highest economic incremental cost. PJM posts the request for load reduction on the PJM website, on the Emergency Conditions page, and on eData, and issues a burst email to the Emergency Load Response majordomo. A separate All-Call message is also issued.

Following PJM's request to reduce load, (i) participants in the Energy Only Option voluntarily may reduce load; and (ii) participants in the Full Program Option are required to reduce load unless they already have reduced load pursuant to the Economic Load Response Program. PJM will dispatch the resources of all Emergency Load Response Program participants (not already dispatched under the Economic Load Response Program) based on the Minimum Dispatch Prices specified in the participants' Emergency Registration Forms.

The Minimum Dispatch Price *and all offers* of Full Program Option *resources and Energy Only Option resources in the Emergency Load Response Program are eligible to* set the real time Locational Marginal Prices ("LMP") *when the Office of the Interconnection has implemented Emergency procedures and such resources are required* to *reduce* demand in the PJM Region*, so long as sufficient data is available to accurately model the resources.* Energy Only Option resource*s must also* satisfy PJM's telemetry requirements.

Participants in the Emergency Load Response Program must provide real-time operational data regarding the availability and status of their resources to PJM, as described in detail in the PJM

Manuals. Operational procedures are described in detail in the ***PJM Manual for Emergency Operations.***

Verification

PJM requires that the load reduction meter data be submitted to PJM within 60 days of the event. If the data are not received within 60 days, no payment for participation is provided. Meter data must be provided for all hours during the day of the Load Management event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. These data files are to be communicated to PJM either via the Load Response Program web site or email. Files that are emailed must be in the PJM-approved file format. Meter data will be forwarded to the EDC and LSE upon receipt, and these parties will then have ten (10) business days to provide feedback to PJM.

Market Settlements

Payment for reducing load is based on the actual kWh relief provided plus the adjustment for losses, subject to the Reporting and Compliance provisions below. The minimum duration of a load reduction request is two hours. The magnitude of capacity relief provided by Full Program Option participants shall be the amount determined in accordance with the Reporting and Compliance provisions below. The magnitude of relief provided by Energy Only Option participants, and the magnitude of energy relief provided by Full Program Option participants, may be less than, equal to, or greater than the kW amount declared on the Emergency Registration Form. Compensation will be provided for reductions in energy consumption during emergency events by Full Program Option participants and Energy Only Option participants regardless of whether the participant's load during the event exceeds its peak load contribution for the applicable Delivery Year.
PJMSettlement pays the applicable LMP to the PJM Member that nominates the load. Payment will be equal to the measured reduction (either measured output of backup generation or the difference between the measured load the hour before the reduction and each hour during the reduction) adjusted for losses times the applicable LMP. If, however, the sum of the hourly energy payments to a participant dispatched by PJM for actual, achieved reductions is not greater than or equal to the offer value (i.e. Minimum Dispatch Price, minimum down time and shut down costs) then the participant will be made whole up to the offer value for its actual, achieved reductions.

Full Program Option participants that fail to provide a load reduction (as measured as set forth in the Reporting and Compliance provisions below) when dispatched by PJM shall be assessed penalties and/or charges as specified in Attachment DD of the PJM Tariff and the Reliability Assurance Agreement, as applicable.

During emergency conditions, costs for emergency purchases in excess of LMP are allocated among PJM Market Buyers in proportion to their increase in net purchases minus real-time dispatch reduction megawatts from the PJM energy market during the hour in the real time market compared to the day-ahead market. Consistent with this pricing methodology, all charges under this program are allocated to purchasers of energy, in proportion to their increase in net

purchases minus real-time dispatch reduction megawatts from the PJM energy market during the hour from day-ahead to real time.

Program charges and credits will appear on the PJM Members monthly bill, as described in the ***PJM Manual for Operating Agreement Accounting and the PJM Manual for Billing.***

Reporting and Compliance

Actual load reductions of Energy Only Option emergency resources will be added back for the purpose of peak load calculations for capacity for the following Delivery Year.

Actual Emergency Load Response and Economic Load Response load reductions for Load Management resources registered as Emergency Load Response Full Program Option or Capacity Only resources which occur from June 1 through September 30, will be added back for the purpose of calculating peak load for capacity for the following Delivery Year, as set forth in the PJM Manuals and consistent with the load response recognized for capacity compliance as set forth in the Reporting and Compliance provisions below. Capacity Only resources are Full Program Option resources that do not receive an energy payment for load reductions during an emergency event.

Actual load reductions of Load Management resources registered as Emergency Load Response Full Program Option or Capacity Only resources used to determine Load Management event and test capacity compliance for Firm Service Level and Guaranteed Load Drop end-use customers shall be equal to the load reduction provided to the electric distribution company as follows and in accordance with the PJM Manuals:

i) For Guaranteed Load Drop end-use customers, the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the metered load ("Load") and then multiplied by the loss factor ("LF") or (b) the current Delivery Year peak load contribution ("PLC") minus the metered load multiplied by the loss factor ("LF"). A load reduction will only be recognized for capacity compliance if the metered load multiplied by the loss factor is less than the current Delivery Year peak load contribution. The calculation is represented by:

   Minimum of {(comparison load – Load) * LF, PLC – (Load * LF)}

   Methodologies for establishing comparison load for Guaranteed Load Drop end-use customers include the following:

   Comparable Day: A single weekday that is comparable to the event or test day and accurately represents what the customer's load would have been absent the event or test.

   Same Day: The customer's average hourly integrated consumption during specified hours on the same day as an emergency or test event.

Customer Baseline: The estimated baseline used to calculate load reductions for end-use customers registered with PJM as economic demand resources.

Regression Analysis: An estimate, based on a regression analysis of the customer's actual loads versus weather, of what the customer's load would have been, had PJM not declared an emergency or test.

Generation: The hourly integrated output from a generator used to reduce the customer's consumption of energy from PJM during an emergency or test event if the generator would not have otherwise been used on the event or test day.

Each of these methodologies is described in greater detail in Manual M-19, ***PJM Manual for Load Forecasting and Analysis***, at Attachment A: Load Drop Estimate Guidelines.

ii) For Firm Service Level end-use customers the current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:

PLC – (Load * LF)

The capacity compliance of Load Management resources that are registered as Emergency Load Response Full Program Option, as determined in accordance with these Reporting and Compliance provisions, shall not affect energy payments to such resources for load reductions during an emergency event, as provided in the Market Settlements provisions above and Attachment DD of the Tariff.

PJM will submit any required reports to FERC on behalf of the Load Response Program participants. PJM will also post this document, as well as any other program-related documentation on the PJM website.

PJM will post on its website a report of demand response activity, and will provide a summary thereof to the PJM Markets and Reliability Committee on an annual basis.

As PJM receives evidence from the electric distribution companies or Load Serving Entities pursuant to section 1.3 of PJM Emergency Load Response Program, PJM will post on its website a list of those Relevant Electric Retail Regulatory Authorities that the electric distribution companies or Load Serving Entities assert prohibit or condition retail participation in PJM's Emergency Load Response Program together with a corresponding reference to the Relevant Electric Retail Regulatory Authority evidence that is provided to PJM by the electric distribution companies or Load Serving Entities.

Non-hourly metered Customer Pilot

Non-hourly metered customers may participate in the Emergency Load Response Program on a pilot basis under the following circumstances. The customer or its Curtailment Service Provider or Load Serving Entity must propose an alternate method for measuring hourly demand reductions. The Office of the Interconnection shall approve alternate measurement mechanisms on a case-by-case basis for a time period specified by the Office of the Interconnection ("Pilot Period"). In the event an alternative measurement mechanism is approved, the Office of the Interconnection shall notify the affected Load Serving Entity(ies) that a proposed alternate measurement mechanism has been approved for a Pilot Period.

Demand reductions by non-hourly metered customers using alternate measurement mechanisms on a pilot basis shall be limited to a combined total of 500 MW of reductions in both the Emergency Load Response Program and the PJM Interchange Energy Market. With the sole exception of the requirement for hourly metering, non-hourly metered customers shall be subject to the rules and procedures for participation in the Emergency Load Response Program. Following completion of a Pilot Period, the alternate method shall be evaluated by the Office of the Interconnection to determine whether such alternate method should be included in the PJM Manuals as an accepted measurement mechanism for demand reductions in the Emergency Load Response Program.

Emergency Load Response Participant Aggregation.

The purpose for aggregation is to allow the participation of End-Use Customers in the Emergency Load Response Program that can provide less than 100 kW of demand response on an individual basis. Emergency Load Response Participant aggregations shall be subject to the following requirements:

i. All End-Use Customers in an aggregation shall be specifically identified;

ii. All End-Use Customers in an aggregation shall be served by the same electric distribution company or Load Serving Entity where the electric distribution company is the Load Serving Entity for all End-Use Customers in the aggregation;

iii. All End-Use Customers in an aggregation that settle at Transmission Zone, existing load aggregate, or node prices shall be located in the same Transmission Zone, existing load aggregate or at the same node, respectively;

iv. Energy settlement will be based on each individual customer's load reductions pursuant to section 3.3A of Schedule 1 of this Agreement, the PJM Reliability Assurance Agreement Among Load Serving Entities in the PJM Region and the PJM Manuals. Capacity compliance will be based on each individual customers' load reductions and then aggregated pursuant to section 3.3A of Schedule 1 of this Agreement, the PJM Reliability Assurance Agreement Among Load Serving Entities in the PJM Region and the PJM Manuals; and

v. Each End-Use Customer site must meet the requirements for market participation by a Demand Resource.

vi. Certain aggregations of End-Use Customers registered as Full Program Option or Capacity Only Option are subject to the "Demand Response Transition Provision for RPM Delivery Years 2012/2013, 2013/2014, and 2014/2015" in Section 5.14A of Attachment DD of the Tariff.

5.10 Auction Clearing Requirements

The Office of the Interconnection shall clear each Base Residual Auction and Incremental Auction for a Delivery Year in accordance with the following:

a) Variable Resource Requirement Curve

The Office of the Interconnection shall determine Variable Resource Requirement Curves for the PJM Region and for such Locational Deliverability Areas as determined appropriate in accordance with subsection (a)(iii) for such Delivery Year to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards. It is recognized that the variable resource requirement reflected in the Variable Resource Requirement Curve can result in an optimized auction clearing in which the level of Capacity Resources committed for a Delivery Year exceeds the PJM Region Reliability Requirement (less the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012, or less the Short-Term Resource Procurement Target for Delivery Years thereafter) or Locational Deliverability Area Reliability Requirement (less the Forecast Zonal ILR Obligation for Delivery Years through May 31, 2012, or less the Short-Term Resource Procurement Target for Delivery Years thereafter for the Zones associated with such LDA) for such Delivery Year. For any auction, the Updated Forecast Peak Load, and Short-Term Resource Procurement Target applicable to such auction, shall be used, and Price Responsive Demand from any applicable approved PRD Plan, including any associated PRD Reservation Prices, shall be reflected in the derivation of the Variable Resource Requirement Curves, in accordance with the methodology specified in the PJM Manuals.

i) Methodology to Establish the Variable Resource Requirement Curve

Prior to the Base Residual Auction, in accordance with the schedule in the PJM Manuals, the Office of the Interconnection shall establish the Variable Resource Requirement Curve for the PJM Region as follows:

- Each Variable Resource Requirement Curve shall be plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis;
- The Variable Resource Requirement Curve for the PJM Region shall be plotted by first combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), (iii) a straight line connecting points (2) and (3), and (iv) a vertical line from point (3) to the x-axis, where:
    - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin ("IRM")% minus

3%) divided by (100% plus IRM%)] minus the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter;

- For point (2), price equals: (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset) divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 1%) divided by (100% plus IRM%)] minus the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter; and

- For point (3), price equals [0.2 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 5%) divided by (100% plus IRM%)] minus the Forecast RTO ILR Obligation for Delivery Years through May 31, 2012 or less the Short-Term Resource Procurement Target for Delivery Years thereafter;

ii) For any Delivery Year, the Office of the Interconnection shall establish a separate Variable Resource Requirement Curve for each LDA for which:

A. the Capacity Emergency Transfer Limit is less than 1.15 times the Capacity Emergency Transfer Objective, as determined by the Office of the Interconnection in accordance with NERC and Applicable Regional Reliability Council guidelines; or

B. such LDA had a Locational Price Adder in any one or more of the three immediately preceding Base Residual Auctions; or

C. such LDA is determined in a preliminary analysis by the Office of the Interconnection to be likely to have a Locational Price Adder, based on historic offer price levels; provided however that for the Base Residual Auction conducted for the Delivery Year commencing on June 1, 2012, the EMAAC, SWMAAC and MAAC LDAs shall employ separate Variable Resource Requirement Curves regardless of the outcome of the above three tests; and provided further that the Office of the Interconnection may establish a separate Variable Resource Requirement Curve for an LDA not otherwise qualifying under the above three tests if it finds that such is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards, in which case the Office of the Interconnection shall post such finding, such LDA, and such

Variable Resource Requirement Curve on its internet site no later than the March 31 last preceding the Base Residual Auction for such Delivery Year. The same process as set forth in subsection (a)(i) shall be used to establish the Variable Resource Requirement Curve for any such LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement and the LDA Short-Term Resource Procurement Target shall be substituted for the PJM Region Short-Term Resource Procurement Target. For purposes of calculating the Capacity Emergency Transfer Limit under this section, all generation resources located in the PJM Region that are, or that qualify to become, Capacity Resources, shall be modeled at their full capacity rating, regardless of the amount of capacity cleared from such resource for the immediately preceding Delivery Year.

iii) Procedure for ongoing review of Variable Resource Requirement Curve shape.

Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall perform a review of the shape of the Variable Resource Requirement Curve, as established by the requirements of the foregoing subsection. Such analysis shall be based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis. Based on the results of such review, PJM shall prepare a recommendation to either modify or retain the existing Variable Resource Requirement Curve shape. The Office of the Interconnection shall post the recommendation and shall review the recommendation through the stakeholder process to solicit stakeholder input. If a modification of the Variable Resource Requirement Curve shape is recommended, the following process shall be followed:

A) If the Office of the Interconnection determines that the Variable Resource Requirement Curve shape should be modified, Staff of the Office of the Interconnection shall propose a new Variable Resource Requirement Curve shape on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

B) The PJM Members shall review the proposed modification to the Variable Resource Requirement Curve shape.

C) The PJM Members shall either vote to endorse the proposed modification, to propose alternate modifications or to recommend no modification by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) The PJM Board of Managers shall consider a proposed modification to the Variable Resource Requirement Curve shape, and the Office of the Interconnection shall file any approved modified Variable Resource Requirement Curve shape with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

iv) Cost of New Entry

A) For the Delivery Year commencing on June 1, 2012, and continuing thereafter unless and until changed pursuant to subsection (B) below, the Cost of New Entry for the PJM Region shall be $112,868 per MW-year. The Cost of New Entry for each LDA shall be determined based upon the Transmission Owner zones that comprise such LDA, as provided in the table below. If an LDA combines transmission zones with differing Cost of New Entry values, the lowest such value shall be used.

Geographic Location Within the PJM Region Encompassing These Zones	**Cost of New Entry in $/MW-Year**
PS, JCP&L, AE, PECO, DPL, RECO ("CONE Area 1")	134,000
BGE, PEPCO ("CONE Area 2")	123,700
AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK ("CONE Area 3")	123,500
PPL, MetEd, Penelec ("CONE Area 4")	130,100
Dominion ("CONE Area 5")	111,000

B) Beginning with the 2013-2014 Delivery Year, the CONE shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable H-W Index, in accordance with the following:

(1) The Applicable H-W Index for any Delivery Year shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in the Total Other Production Plant Index shown in the Handy-Whitman Index of Public Utility Construction Costs for the North Atlantic Region for purposes of CONE Areas 1, 2, and 4, for the North Central Region for purposes of CONE Area 3, and for the South Atlantic Region for purposes of CONE Area 5.

(2) The CONE in a CONE Area shall be adjusted prior to the Base Residual Auction for each Delivery Year by applying the Applicable H-W Index for such CONE Area to the Benchmark CONE for such CONE Area.

(3) The Benchmark CONE for a CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year.

(4) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vii)(C) or any filing to establish new or revised CONE Areas.

v) Net Energy and Ancillary Services Revenue Offset

A) The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (A) the annual average of the revenues that would have been received by the Reference Resource from the PJM energy markets during a period of three consecutive calendar years preceding the time of the determination, based on (1) the heat rate and other characteristics of such Reference Resource; (2) fuel prices reported during such period at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals, assumed variable operation and maintenance expenses for such resource of $6.47 per MWh, and actual PJM hourly average Locational Marginal Prices recorded in the PJM Region during such period; and (3) an assumption that the Reference Resource would be dispatched for both the Day-Ahead and Real-Time Energy Markets on a Peak-Hour Dispatch basis; plus (B) ancillary service revenues of $2,199 per MW-year.

B) The Office of the Interconnection also shall determine a Net Energy and Ancillary Service Revenue Offset each year for each sub-region of the PJM Region for which the Cost of New Entry is determined as identified above, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the average hourly LMPs for the Zone in which the Reference Resource was assumed to be installed for purposes of the CONE estimate (as specified in the PJM Manuals) shall be used in place of the PJM Region average hourly LMPs; (2) if such sub-region was not integrated into the PJM Region for the entire applicable period, then the offset shall be calculated using only those whole calendar years during which the sub-region was integrated; and (3) a posted fuel pricing point in such sub-region, if available, and (if such pricing point is not available) a fuel

transmission adder appropriate to each assumed Cost of New Entry location from an appropriate PJM Region pricing point shall be used for each such sub-region.

vii) Process for Establishing Parameters of Variable Resource Requirement Curve

A) The parameters of the Variable Resource Requirement Curve will be established prior to the conduct of the Base Residual Auction for a Delivery Year and will be used for such Base Residual Auction.

B) The Office of the Interconnection shall determine the PJM Region Reliability Requirement and the Locational Deliverability Area Reliability Requirement for each Locational Deliverability Area for which a Variable Resource Requirement Curve has been established for such Base Residual Auction on or before February 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values will be applied, in accordance with the Reliability Assurance Agreement.

C) Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall review the calculation of the Cost of New Entry for each CONE Area.

1) If the Office of the Interconnection determines that the Cost of New Entry values should be modified, the Staff of the Office of the Interconnection shall propose new Cost of New Entry values on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

2) The PJM Members shall review the proposed values.

3) The PJM Members shall either vote to endorse the proposed values or propose alternate values by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

4) The PJM Board of Managers shall consider Cost of New Entry values, and the Office of the Interconnection shall file any approved modified Cost of New Entry values with the FERC by December 1, prior to the conduct of the Base

Residual Auction for the first Delivery Year in which the new values would be applied.

D) Beginning no later than for the Delivery Year that commences June 1, 2015, and continuing no later than for every third Delivery Year thereafter, the Office of the Interconnection shall review the methodology set forth in this Attachment for determining the Net Energy and Ancillary Services Revenue Offset for the PJM Region and for each Zone.

1) If the Office of the Interconnection determines that the Net Energy and Ancillary Services Revenue Offset methodology should be modified, Staff of the Office of the Interconnection shall propose a new Net Energy and Ancillary Services Revenue Offset methodology on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

2) The PJM Members shall review the proposed methodology.

3) The PJM Members shall either vote to endorse the proposed methodology or propose an alternate methodology by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

4) The PJM Board of Managers shall consider the Net Revenue Offset methodology, and the Office of the Interconnection shall file any approved modified Net Energy and Ancillary Services Revenue Offset values with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

b) Locational Requirements

The Office of Interconnection shall establish locational requirements prior to the Base Residual Auction to quantify the amount of Unforced Capacity that must be committed in each Locational Deliverability Area, in accordance with the PJM Reliability Assurance Agreement.

c) Minimum Annual Resource Requirements

Prior to the Base Residual Auction and each Incremental Auction for each Delivery Year, beginning with the Delivery Year that starts on June 1, 2014, the Office of the Interconnection shall establish the Minimum Annual Resource Requirement and the Minimum Extended

Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year.

d) Preliminary PJM Region Peak Load Forecast for the Delivery Year

The Office of the Interconnection shall establish the Preliminary PJM Region Load Forecast for the Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the Base Residual Auction for such Delivery Year.

e) Updated PJM Region Peak Load Forecasts for Incremental Auctions

The Office of the Interconnection shall establish the updated PJM Region Peak Load Forecast for a Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the First, Second, and Third Incremental Auction for such Delivery Year.

Sections of the
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1.38.01 Regional RTEP Project.

"Regional RTEP Project" shall mean a transmission expansion or enhancement rated at 230 kV or above which is required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.

1.38.01A Relevant Electric Retail Regulatory Authority:

An entity that has jurisdiction over and establishes prices and policies for competition for providers of retail electric service to end-customers, such as the city council for a municipal utility, the governing board of a cooperative utility, the state public utility commission or any other such entity.

1.38A Regulation Zone.

"Regulation Zone" shall mean any of those one or more geographic areas, each consisting of a combination of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, regulation service.

1.39 Related Parties.

"Related Parties" shall mean, solely for purposes of the governance provisions of this Agreement: (i) any generation and transmission cooperative and one of its distribution cooperative members; and (ii) any joint municipal agency and one of its members. For purposes of this Agreement, representatives of state or federal government agencies shall not be deemed Related Parties with respect to each other, and a public body's regulatory authority, if any, over a Member shall not be deemed to make it a Related Party with respect to that Member.

1.40 Reliability Assurance Agreement.

"Reliability Assurance Agreement" shall mean that certain Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region, on file with FERC as PJM Interconnection, L.L.C. Rate Schedule FERC. No .42, establishing obligations, standards and procedures for maintaining the reliable operation of the PJM Region.

1.40A *Reserve Zone*.

"Reserve Zone" shall mean any of those geographic areas consisting of a combination of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, reserve service.

1.40B [Reserved].

1.40C SERC.

"SERC" or "Southeastern Electric Reliability Council" shall mean the reliability council under section 202 of the Federal Power Act established pursuant to the SERC Agreement dated January 14, 1970, or any successor thereto.

1.41 Sector Votes.

"Sector Votes" shall mean the affirmative and negative votes of each sector of a Senior Standing Committee, as specified in Section 8.4.

1.41A Senior Standing Committees.

"Senior Standing Committees" shall mean the Members Committee, and the Markets, and Reliability Committee, as established in Sections 8.1 and 8.6.

1.41A.01 [Reserved].

1.41A.02 [Reserved].

1.41A.03 [Reserved].

1.41B Standing Committees.

"Standing Committees" shall mean the Members Committee, the committees established and maintained under Section 8.6, and such other committees as the Members Committee may establish and maintain from time to time.

1.42 State.

"State" shall mean the District of Columbia and any State or Commonwealth of the United States.

1.42.01 State Certification.

"State Certification" shall mean the Certification of an Authorized Commission, pursuant to Section 18 of this Agreement, the form of which is appended to this Agreement as Schedule 10A, wherein the Authorized Commission identifies all Authorized Persons employed or retained by such Authorized Commission, a copy of which shall be filed with FERC.

1.42A State Consumer Advocate.

"State Consumer Advocate" shall mean a legislatively created office from any State, all or any part of the territory of which is within the PJM Region, and the District of Columbia established,

inter alia, for the purpose of representing the interests of energy consumers before the utility regulatory commissions of such states and the District of Columbia and the FERC.

1.42A.01 Subregional RTEP Project.

"Subregional RTEP Project" shall mean a transmission expansion or enhancement rated below 230 kV which is requiredfor compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.

1.42A.02 Supplemental Project.

"Supplemental Project" shall mean a Regional RTEP Project(s) or Subregional RTEP Project(s), which is not required for compliance with the following PJM criteria: System reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.

1.42B *[Reserved]*

1.43 System.

"System" shall mean the interconnected electric supply system of a Member and its interconnected subsidiaries exclusive of facilities which it may own or control outside of the PJM Region. Each Member may include in its system the electric supply systems of any party or parties other than Members which are within the PJM Region, provided its interconnection agreements with such other party or parties do not conflict with such inclusion.

1.43A Third Party Request.

"Third Party Request" shall mean any request or demand by any entity upon an Authorized Person or an Authorized Commission for release or disclosure of confidential information provided to the Authorized Person or Authorized Commission by the Office of the Interconnection or PJM Market Monitor. A Third Party Request shall include, but shall not be limited to, any subpoena, discovery request, or other request for confidential information made by any: (i) federal, state, or local governmental subdivision, department, official, agency or court, or (ii) arbitration panel, business, company, entity or individual.

1.44 Transmission Facilities.

"Transmission Facilities" shall mean facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERC's Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the transmission system of the PJM Region and integrated into the planning and operation of such to serve all of the power and transmission customers within such region.

1.45 Transmission Owner.

"Transmission Owner" shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

1.46 [Reserved.]

1.3 Definitions.

1.3.1 Acceleration Request.

"Acceleration Request" shall mean a request pursuant to section 1.9.4A of this Schedule to accelerate or reschedule a transmission outage scheduled pursuant to sections 1.9.2 or 1.9.4.

1.3.1A Auction Revenue Rights.

"Auction Revenue Rights" or "ARRs" shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Section 7.4 of this Schedule.

1.3.1B Auction Revenue Rights Credits.

"Auction Revenue Rights Credits" shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Section 7.4.3 of this Schedule.

1.3.1B.01 Batch Load Demand Resource.

"Batch Load Demand Resource" shall mean a Demand Resource that has a cyclical production process such that at most times during the process it is consuming energy, but at consistent regular intervals, ordinarily for periods of less than ten minutes, it reduces its consumption of energy for its production processes to minimal or zero megawatts.

1.3.1B.02 Congestion Price.

"Congestion Price" shall mean the congestion component of the Locational Marginal Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.1B.03 Curtailment Service Provider.

"Curtailment Service Provider" or "CSP" shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market by causing a reduction in demand.

1.3.1B.04 Day-ahead Congestion Price.

"Day-ahead Congestion Price" shall mean the Congestion Price resulting from the Day-ahead Energy Market.

1.3.1C Day-ahead Energy Market.

"Day-ahead Energy Market" shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Section 1.10 of this Schedule.

1.3.1C.01 Day-ahead Loss Price.

"Day-ahead Loss Price" shall mean the Loss Price resulting from the Day-ahead Energy Market.

1.3.1D Day-ahead Prices.

"Day-ahead Prices" shall mean the Locational Marginal Prices resulting from the Day-ahead Energy Market.

1.3.1D.01 Day-ahead Scheduling Reserves.

"Day-ahead Scheduling Reserves" shall mean thirty-minute reserves as defined by the Reliability First Corporation and SERC.

1.3.1D.02 Day-ahead Scheduling Reserves Requirement.

"Day-ahead Scheduling Reserves Requirement" shall mean the thirty-minute reserve requirement for the PJM Region established consistent with Reliability First Corporation and SERC reliability standards, or those of any additional and/or successor regional reliability organization(s) that are responsible for establishing reliability requirements for the PJM Region, plus any additional thirty-minute reserves scheduled in response to an RTO-wide Hot or Cold Weather Alert or other reasons for conservative operations.

1.3.1D.03 Day-ahead Scheduling Reserves Resources.

"Day-ahead Scheduling Reserves Resources" shall mean synchronized and non-synchronized generation resources and Demand Resources electrically located within the PJM Region that are capable of providing Day-ahead Scheduling Reserves.

1.3.1D.04 Day-ahead Scheduling Reserves Market.

"Day-ahead Scheduling Reserves Market" shall mean the schedule of commitments for the purchase or sale of Day-ahead Scheduling Reserves developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Section 1.10 of this Schedule.

1.3.1D.05 Day-ahead System Energy Price.

"Day-ahead System Energy Price" shall mean the System Energy Price resulting from the Day-ahead Energy Market.

1.3.1E Decrement Bid.

"Decrement Bid" shall mean a bid to purchase energy at a specified location in the Day-ahead Energy Market. An accepted Decrement Bid results in scheduled load at the specified location in the Day-ahead Energy Market.

1.3.1E.01 Demand Resource.

"Demand Resource" shall mean a resource with the capability to provide a reduction in demand.

1.3.1F Dispatch Rate.

"Dispatch Rate" shall mean the control signal, expressed in dollars per megawatt-hour, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by the Office of the Interconnection in accordance with the Offer Data.

1.3.1G Energy Storage Resource.

"Energy Storage Resource" shall mean flywheel or battery storage facility solely used for short term storage and injection of energy at a later time to participate in the PJM energy and/or Ancilliary Services markets as a Market Seller.

1.3.2 Equivalent Load.

"Equivalent Load" shall mean the sum of a Market Participant's net system requirements to serve its customer load in the PJM Region, if any, plus its net bilateral transactions.

1.3.2A Economic Load Response Participant.

"Economic Load Response Participant" shall mean a Member or Special Member that qualifies under Section 1.5A of this Schedule to participate in the PJM Interchange Energy Market through reductions in demand.

1.3.2A.01 Economic Minimum.

"Economic Minimum" shall mean the lowest incremental MW output level a unit can achieve while following economic dispatch.

1.3.2B Energy Market Opportunity Cost.

"Energy Market Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of available run hours due to limitations imposed on the unit by Applicable Laws and Regulations (as defined in PJM Tariff), and (b) the forecasted future hourly Locational Marginal Price at which the generating

unit could run while not violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Schedule 2 of the Operating Agreement.

1.3.3 External Market Buyer.

"External Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for consumption by end-users outside the PJM Region, or for load in the PJM Region that is not served by Network Transmission Service.

1.3.4 External Resource.

"External Resource" shall mean a generation resource located outside the metered boundaries of the PJM Region.

1.3.5 Financial Transmission Right.

"Financial Transmission Right" or "FTR" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2 of this Schedule.

1.3.5A Financial Transmission Right Obligation.

"Financial Transmission Right Obligation" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2(b) of this Schedule.

1.3.5B Financial Transmission Right Option.

"Financial Transmission Right Option" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2(c) of this Schedule.

1.3.6 Generating Market Buyer.

"Generating Market Buyer" shall mean an Internal Market Buyer that is a Load Serving Entity that owns or has contractual rights to the output of generation resources capable of serving the Market Buyer's load in the PJM Region, or of selling energy or related services in the PJM Interchange Energy Market or elsewhere.

1.3.7 Generator Forced Outage.

"Generator Forced Outage" shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the PJM Manuals. A reduction in output or

removal from service of a generating unit in response to changes in market conditions shall not constitute a Generator Forced Outage.

1.3.8 Generator Maintenance Outage.

"Generator Maintenance Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform necessary repairs on specific components of the facility, if removal of the facility meets the guidelines specified in the PJM Manuals.

1.3.9 Generator Planned Outage.

"Generator Planned Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the Office of the Interconnection in accordance with the PJM Manuals.

1.3.9A Increment Bid.

"Increment Bid" shall mean an offer to sell energy at a specified location in the Day-ahead Energy Market. An accepted Increment Bid results in scheduled generation at the specified location in the Day-ahead Energy Market.

1.3.9B Interface Pricing Point.

"Interface Pricing Point" shall have the meaning specified in section 2.6A.

1.3.10 Internal Market Buyer.

"Internal Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for ultimate consumption by end-users inside the PJM Region that are served by Network Transmission Service.

1.3.11 Inadvertent Interchange.

"Inadvertent Interchange" shall mean the difference between net actual energy flow and net scheduled energy flow into or out of the individual Control Areas operated by PJM.

1.3.11.01 Load Management.

"Load Management" shall mean either a Demand Resource ("DR") or an Interruptible Load for Reliability ("ILR") resource, both as defined in the Reliability Assurance Agreement.

1.3.11A Load Reduction Event.

"Load Reduction Event" shall mean a reduction in demand by a Member or Special Member for the purpose of participating in the PJM Interchange Energy Market.

1.3.11B Loss Price.

"Loss Price" shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.12 Market Operations Center.

"Market Operations Center" shall mean the equipment, facilities and personnel used by or on behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

1.3.12A Maximum Emergency.

"Maximum Emergency" shall mean the designation of all or part of the output of a generating unit for which the designated output levels may require extraordinary procedures and therefore are available to the Office of the Interconnection only when the Office of the Interconnection declares a Maximum Generation Emergency and requests generation designated as Maximum Emergency to run. The Office of the Interconnection shall post on the PJM website the aggregate amount of megawatts that are classified as Maximum Emergency.

1.3.13 Maximum Generation Emergency.

"Maximum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection to address either a generation or transmission emergency in which the Office of the Interconnection anticipates requesting one or more Generation Capacity Resources, or Non-Retail Behind The Meter Generation resources to operate at its maximum net or gross electrical power output, subject to the equipment stress limits for such Generation Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

1.3.14 Minimum Generation Emergency.

"Minimum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

1.3.14A NERC Interchange Distribution Calculator.

"NERC Interchange Distribution Calculator" shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

1.3.14B Net Benefits Test.

"Net Benefits Test" shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Section 3.3A.4 of this Schedule.

1.3.15 Network Resource.

"Network Resource" shall have the meaning specified in the PJM Tariff.

1.3.16 Network Service User.

"Network Service User" shall mean an entity using Network Transmission Service.

1.3.17 Network Transmission Service.

"Network Transmission Service" shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part III of the PJM Tariff, or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

1.3.17A Non-Regulatory Opportunity Cost.

"Non-Regulatory Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, (ii) a fuel supply limitation, for up to one year, resulting from an event of force majeure; and, (b) the forecasted future hourly Locational Marginal Price at which the generating unit could run while not violating such limitations. Non-Regulatory Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same period of time in which the unit is bound by the referenced restrictions, and is reflected in the rules set forth in PJM Manual 15. Non-Regulatory Opportunity Costs shall be limited to those resources which are specifically delineated in Schedule 2 of the Operating Agreement.

1.3.17B Non-Synchronized Reserve.

"Non-Synchronized Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

1.3.17C Non-Synchronized Reserve Event.

"Non-Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources and/or Demand Resources able, assigned or self-scheduled, to provide

Non-Synchronized Reserve within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-schedule Non-Synchronized Reserve capability.

1.3.17D Non-Variable Loads.

"Non-Variable Loads" shall have the meaning specified in section 1.5A.6 of this Schedule.

1.3.18 Normal Maximum Generation.

"Normal Maximum Generation" shall mean the highest output level of a generating resource under normal operating conditions.

1.3.19 Normal Minimum Generation.

"Normal Minimum Generation" shall mean the lowest output level of a generating resource under normal operating conditions.

1.3.20 Offer Data.

"Offer Data" shall mean the scheduling, operations planning, dispatch, new resource, and other data and information necessary to schedule and dispatch generation resources and Demand Resource(s) for the provision of energy and other services and the maintenance of the reliability and security of the transmission system in the PJM Region, and specified for submission to the PJM Interchange Energy Market for such purposes by the Office of the Interconnection.

1.3.21 Office of the Interconnection Control Center.

"Office of the Interconnection Control Center" shall mean the equipment, facilities and personnel used by the Office of the Interconnection to coordinate and direct the operation of the PJM Region and to administer the PJM Interchange Energy Market, including facilities and equipment used to communicate and coordinate with the Market Participants in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

1.3.21A On-Site Generators.

"On-Site Generators" shall mean generation facilities (including Behind The Meter Generation) that (i) are not Capacity Resources, (ii) are not injecting into the grid, (iii) are either synchronized or non-synchronized to the Transmission System, and (iv) can be used to reduce demand for the purpose of participating in the PJM Interchange Energy Market.

1.3.22 Operating Day.

"Operating Day" shall mean the daily 24 hour period beginning at midnight for which transactions on the PJM Interchange Energy Market are scheduled.

1.3.23 Operating Margin.

"Operating Margin" shall mean the incremental adjustments, measured in megawatts, required in PJM Region operations in order to accommodate, on a first contingency basis, an operating contingency in the PJM Region resulting from operations in an interconnected Control Area. Such adjustments may result in constraints causing Transmission Congestion Charges, or may result in Ancillary Services charges pursuant to the PJM Tariff.

1.3.24 Operating Margin Customer.

"Operating Margin Customer" shall mean a Control Area purchasing Operating Margin pursuant to an agreement between such other Control Area and the LLC.

1.3.25 PJM Interchange.

"PJM Interchange" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load exceeds, or is exceeded by, the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup; or (c) the hourly scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the hourly net metered output of any other Market Seller; or (e) the hourly scheduled deliveries of Spot Market Energy to an External Market Buyer; or (f) the hourly scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

1.3.26 PJM Interchange Export.

"PJM Interchange Export" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load is exceeded by the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup sales; or (c) the hourly scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the hourly net metered output of any other Market Seller.

1.3.27 PJM Interchange Import.

"PJM Interchange Import" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load exceeds the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup purchases; or (c) the hourly scheduled deliveries of Spot Market Energy to an External Market Buyer; or (d) the hourly scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

1.3.28 PJM Open Access Same-time Information System.

"PJM Open Access Same-time Information System" shall mean the electronic communication system for the collection and dissemination of information about transmission services in the PJM Region, established and operated by the Office of the Interconnection in accordance with FERC standards and requirements.

1.3.28A Planning Period Quarter.

"Planning Period Quarter" shall mean any of the following three month periods in the Planning Period: June, July and August; September, October and November; December, January and February; or March, April and May.

1.3.28B Planning Period Balance.

"Planning Period Balance" shall mean the entire period of time remaining in the Planning Period following the month that a monthly auction is conducted.

1.3.29 Point-to-Point Transmission Service.

"Point-to-Point Transmission Service" shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part II of the PJM Tariff.

1.3.29A PRD Curve

PRD Curve shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29B PRD Provider

PRD Provider shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29C PRD Reservation Price

PRD Reservation Price shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29D PRD Substation

PRD Substation shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29E Price Responsive Demand

Price Responsive Demand shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29F Primary Reserve
"Primary Reserve" shall mean the total reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten

minutes of a request from the Office of the Interconnection dispatcher, and is comprised of both Synchronized Reserve and Non-Synchronized Reserve.

1.3.30 Ramping Capability.

"Ramping Capability" shall mean the sustained rate of change of generator output, in megawatts per minute.

1.3.30.01 Real-time Congestion Price.

"Real-time Congestion Price" shall mean the Congestion Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30.02 Real-time Loss Price.

"Real-time Loss Price" shall mean the Loss Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30A Real-time Prices.

"Real-time Prices" shall mean the Locational Marginal Prices resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30B Real-time Energy Market.

"Real-time Energy Market" shall mean the purchase or sale of energy and payment of Transmission Congestion Charges for quantity deviations from the Day-ahead Energy Market in the Operating Day.

1.3.30B.01 Real-time System Energy Price.

"Real-time System Energy Price" shall mean the System Energy Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.31 Regulation.

"Regulation" shall mean the capability of a specific generation resource or Demand Resource with appropriate telecommunications, control and response capability to increase or decrease its output or adjust load in response to a regulating control signal, in accordance with the specifications in the PJM Manuals.

1.3.31.001 Reserve Penalty Factor.

"Reserve Penalty Factor" shall mean the cost, in $/MWh, associated with being unable to meet a specific reserve requirement in a Reserve Zone. A Reserve Penalty Factor will be defined for each reserve requirement in a Reserve Zone.

1.3.31.01 Residual Auction Revenue Rights.

"Residual Auction Revenue Rights" shall mean incremental stage 1 Auction Revenue Rights created within a Planning Period by an increase in transmission system capability or a change in any other relevant factor that was not modeled pursuant to section 7.5 of Schedule 1 of this Agreement in compliance with section 7.4.2(h) of Schedule 1 of this Agreement, and, if modeled, would have increased the amount of stage 1 Auction Revenue Rights allocated pursuant to section 7.4.2 of Schedule 1 of this Agreement; provided that, the foregoing notwithstanding, Residual Auction Revenue Rights shall exclude: 1) Incremental Auction Revenue Rights allocated pursuant to Part VI of the Tariff; and 2) Auction Revenue Rights allocated to entities that are assigned cost responsibility pursuant to Schedule 6 of this Agreement for transmission upgrades that create such rights.

1.3.31.02 Special Member.

"Special Member" shall mean an entity that satisfies the requirements of Section 1.5A.02 of this Schedule or the special membership provisions established under the Emergency Load Response Program.

1.3.31A [Reserved.]

1.3.31B [Reserved.]

1.3.32 Spot Market Backup.

"Spot Market Backup" shall mean the purchase of energy from, or the delivery of energy to, the PJM Interchange Energy Market in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason.

1.3.33 Spot Market Energy.

"Spot Market Energy" shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at System Energy Prices determined as specified in Section 2 of this Schedule.

1.3.33A State Estimator.

"State Estimator" shall mean the computer model of power flows specified in Section 2.3 of this Schedule.

1.3.33B Station Power.

"Station Power" shall mean energy used for operating the electric equipment on the site of a generation facility located in the PJM Region or for the heating, lighting, air-conditioning and

office equipment needs of buildings on the site of such a generation facility that are used in the operation, maintenance, or repair of the facility. Station Power does not include any energy (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility; (iii) used for compressors at a compressed air energy storage facility; (iv) used for charging an Energy Storage Resource; or (v) used in association with restoration or black start service.

1.3.33B.01 Synchronized Reserve.

"Synchronized Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes from the request of the Office of the Interconnection dispatcher, and is provided by equipment that is electrically synchronized to the Transmission System.

1.3.33B.02 Synchronized Reserve Event.

"Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources and/or Demand Resources able, assigned or self-scheduled to provide Synchronized Reserve, within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-scheduled Synchronized Reserve capability.

1.3.33B.03 System Energy Price.

"System Energy Price" shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.33C Target Allocation.

"Target Allocation" shall mean the allocation of Transmission Congestion Credits as set forth in Section 5.2.3 of this Schedule or the allocation of Auction Revenue Rights Credits as set forth in Section 7.4.3 of this Schedule.

1.3.34 Transmission Congestion Charge.

"Transmission Congestion Charge" shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses in accordance with Section 9.3, which shall be calculated and allocated as specified in Section 5.1 of this Schedule.

1.3.35 Transmission Congestion Credit.

"Transmission Congestion Credit" shall mean the allocated share of total Transmission Congestion Charges credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section 5.2 of this Schedule.

1.3.36 Transmission Customer.

"Transmission Customer" shall mean an entity using Point-to-Point Transmission Service.

1.3.37 Transmission Forced Outage.

"Transmission Forced Outage" shall mean an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the PJM Manuals. A removal from service of a transmission facility at the request of the Office of the Interconnection to improve transmission capability shall not constitute a Forced Transmission Outage.

1.3.37A Transmission Loading Relief.

"Transmission Loading Relief" shall mean NERC's procedures for preventing operating security limit violations, as implemented by PJM as the security coordinator responsible for maintaining transmission security for the PJM Region.

1.3.37B Transmission Loading Relief Customer.

"Transmission Loading Relief Customer" shall mean an entity that, in accordance with Section 1.10.6A, has elected to pay Transmission Congestion Charges during Transmission Loading Relief in order to continue energy schedules over contract paths outside the PJM Region that are increasing the cost of energy in the PJM Region.

1.3.37C Transmission Loss Charge.

"Transmission Loss Charge" shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Section 5 of this Schedule.

1.3.38 Transmission Planned Outage.

"Transmission Planned Outage" shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in this Agreement or the PJM Manuals.

1.3.38A Variable Loads.

"Variable Loads" shall have the meaning specified in section 1.5A.6 of this Schedule.

1.3.39 Zonal Base Load.

"Zonal Base Load" shall mean the lowest daily zonal peak load from the twelve month period ending October 21 of the calendar year immediately preceding the calendar year in which an

annual Auction Revenue Right allocation is conducted, increased by the projected load growth rate for the relevant Zone.

1.7 General.

1.7.1 Market Sellers.

Only Market Sellers shall be eligible to submit offers to the Office of the Interconnection for the sale of electric energy or related services in the PJM Interchange Energy Market. Market Sellers shall comply with the prices, terms, and operating characteristics of all Offer Data submitted to and accepted by the PJM Interchange Energy Market.

1.7.2 Market Buyers.

Only Market Buyers shall be eligible to purchase energy or related services in the PJM Interchange Energy Market. Market Buyers shall comply with all requirements for making purchases from the PJM Interchange Energy Market.

1.7.2A Economic Load Response Participants.

Only Economic Load Response Participants shall be eligible to participate in the Real-time Energy Market and the Day-ahead Energy Market by submitting offers to the Office of the Interconnection to reduce demand.

1.7.3 Agents.

A Market Participant may participate in the PJM Interchange Energy Market through an agent, provided that the Market Participant informs the Office of the Interconnection in advance in writing of the appointment of such agent. A Market Participant participating in the PJM Interchange Energy Market through an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the PJM Interchange Energy Market, and shall ensure that any such agent complies with the requirements of this Agreement.

1.7.4 General Obligations of the Market Participants.

(a) In performing its obligations to the Office of the Interconnection hereunder, each Market Participant shall at all times (i) follow Good Utility Practice, (ii) comply with all applicable laws and regulations, (iii) comply with the applicable principles, guidelines, standards and requirements of FERC, NERC and Applicable Regional Reliability Councils, (iv) comply with the procedures established for operation of the PJM Interchange Energy Market and PJM Region and (v) cooperate with the Office of the Interconnection as necessary for the operation of the PJM Region in a safe, reliable manner consistent with Good Utility Practice.

(b) Market Participants shall undertake all operations in or affecting the PJM Interchange Energy Market and the PJM Region including but not limited to compliance with all Emergency procedures, in accordance with the power and authority of the Office of the Interconnection with respect to the operation of the PJM Interchange Energy Market and the PJM Region as established in this Agreement, and as specified in the Schedules to this Agreement and the PJM Manuals. Failure to comply with the foregoing operational requirements shall subject a Market

Participant to such reasonable charges or other remedies or sanctions for non-compliance as may be established by the PJM Board, including legal or regulatory proceedings as authorized by the PJM Board to enforce the obligations of this Agreement.

(c) The Office of the Interconnection may establish such committees with a representative of each Market Participant, and the Market Participants agree to provide appropriately qualified personnel for such committees, as may be necessary for the Office of the Interconnection and PJMSettlement to perform its obligations hereunder.

(d) All Market Participants shall provide to the Office of the Interconnection the scheduling and other information specified in the Schedules to this Agreement, and such other information as the Office of the Interconnection may reasonably require for the reliable and efficient operation of the PJM Region and PJM Interchange Energy Market, and for compliance with applicable regulatory requirements for posting market and related information. Such information shall be provided as much in advance as possible, but in no event later than the deadlines established by the Schedules to this Agreement, or by the Office of the Interconnection in conformance with such Schedules. Such information shall include, but not be limited to, maintenance and other anticipated outages of generation or transmission facilities, scheduling and related information on bilateral transactions and self-scheduled resources, and implementation of active load management, interruption of load, Price Responsive Demand, and other load reduction measures. The Office of the Interconnection shall abide by appropriate requirements for the non-disclosure and protection of any confidential or proprietary information given to the Office of the Interconnection by a Market Participant. Each Market Participant shall maintain or cause to be maintained compatible information and communications systems, as specified by the Office of the Interconnection, required to transmit scheduling, dispatch, or other time-sensitive information to the Office of the Interconnection in a timely manner.

(e) Subject to the requirements for Economic Load Response participants in section 1.5A above, each Market Participant shall install and operate, or shall otherwise arrange for, metering and related equipment capable of recording and transmitting all voice and data communications reasonably necessary for the Office of the Interconnection and PJMSettlement to perform the services specified in this Agreement. A Market Participant that elects to be separately billed for its PJM Interchange shall, to the extent necessary, be individually metered in accordance with Section 14 of this Agreement, or shall agree upon an allocation of PJM Interchange between it and the Market Participant through whose meters the unmetered Market Participant's PJM Interchange is delivered. The Office of the Interconnection shall be notified of the allocation by the foregoing Market Participants.

(f) Each Market Participant shall operate, or shall cause to be operated, any generating resources owned or controlled by such Market Participant that are within the PJM Region or otherwise supplying energy to or through the PJM Region in a manner that is consistent with the standards, requirements or directions of the Office of the Interconnection and that will permit the Office of the Interconnection to perform its obligations under this Agreement; provided, however, no Market Participant shall be required to take any action that is inconsistent with Good Utility Practice or applicable law.

(g) Each Market Participant shall follow the directions of the Office of the Interconnection to take actions to prevent, manage, alleviate or end an Emergency in a manner consistent with this Agreement and the procedures of the PJM Region as specified in the PJM Manuals.

(h) Each Market Participant shall obtain and maintain all permits, licenses or approvals required for the Market Participant to participate in the PJM Interchange Energy Market in the manner contemplated by this Agreement.

(i) Consistent with Section 36.1.1 of the PJM Tariff, to the extent its generating facility is dispatchable, a Market Participant shall submit an Economic Minimum in the Real-time Energy Market that is no greater than the higher of its physical operating minimum or its Capacity Interconnection Rights, as that term is defined in the PJM Tariff, associated with such generating facility under its Interconnection Service Agreement under Attachment O of the PJM Tariff or a wholesale market participation agreement.

1.7.5 Market Operations Center.

Each Market Participant shall maintain a Market Operations Center, or shall make appropriate arrangements for the performance of such services on its behalf. A Market Operations Center shall meet the performance, equipment, communications, staffing and training standards and requirements specified in this Agreement for the scheduling and completion of transactions in the PJM Interchange Energy Market and the maintenance of the reliable operation of the PJM Region, and shall be sufficient to enable (i) a Market Seller or an Economic Load Response Participant to perform all terms and conditions of its offers to the PJM Interchange Energy Market, and (ii) a Market Buyer or an Economic Load Response Participant to conform to the requirements for purchasing from the PJM Interchange Energy Market.

1.7.6 Scheduling and Dispatching.

(a) The Office of the Interconnection shall schedule and dispatch in real-time generation resources and/or Demand Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Sellers, continuing until sufficient generation resources and/or Demand Resources are dispatched to serve the PJM Interchange Energy Market energy purchase requirements under normal system conditions of the Market Buyers (taking into account any reductions to such requirements in accordance with PRD Curves properly submitted by PRD Providers), as well as the requirements of the PJM Region for ancillary services provided by generation resources and/or Demand Resources, in accordance with this Agreement. Such scheduling and dispatch shall recognize transmission constraints on coordinated flowgates external to the Transmission System in accordance with Appendix A to the Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38) and on other such flowgates that are coordinated in accordance with agreements between the LLC and other entities. Scheduling and dispatch shall be conducted in accordance with this Agreement.

(b) The Office of the Interconnection shall undertake to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the PJM Interchange Energy Market, and any relevant procedures of another Control Area, or any tariff (including the PJM Tariff). Upon determining that any such conflict or incompatibility exists, the Office of the Interconnection shall propose tariff or procedural changes, and undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

(c) To protect its generation or distribution facilities, or local Transmission Facilities not under the monitoring responsibility and dispatch control of the Office of the Interconnection, an entity may request that the Office of the Interconnection schedule and dispatch generation or reductions in demand to meet a limit on Transmission Facilities different from that which the Office of the Interconnection has determined to be required for reliable operation of the Transmission System. To the extent consistent with its other obligations under this Agreement, the Office of the Interconnection shall schedule and dispatch generation and reductions in demand in accordance with such request. An entity that makes a request pursuant to this section 1.7.6(c) shall be responsible for all generation and other costs resulting from its request that would not have been incurred by operating the Transmission System and scheduling and dispatching generation in the manner that the Office of the Interconnection otherwise has determined to be required for reliable operation of the Transmission System.

1.7.7 Pricing.

The price paid for energy bought and sold in the PJM Interchange Energy Market and for demand reductions will reflect the hourly Locational Marginal Price at each load and generation bus, determined by the Office of the Interconnection in accordance with this Agreement. Transmission Congestion Charges and Transmission Loss Charges, which shall be determined by differences in Congestion Prices and Loss Prices in an hour, shall be calculated by the Office of the Interconnection, and collected by PJMSettlement, and the revenues therefrom shall be disbursed by PJMSettlement in accordance with this Schedule.

1.7.8 Generating Market Buyer Resources.

A Generating Market Buyer may elect to self-schedule its generation resources up to that Generating Market Buyer's Equivalent Load, in accordance with and subject to the procedures specified in this Schedule, and the accounting and billing requirements specified in Section 3 to this Schedule. PJMSettlement shall not be a contracting party with respect to such self-scheduled or self-supplied transactions.

1.7.9 Delivery to an External Market Buyer.

A purchase of Spot Market Energy by an External Market Buyer shall be delivered to a bus or buses at the electrical boundaries of the PJM Region specified by the Office of the Interconnection, or to load in such area that is not served by Network Transmission Service, using Point-to-Point Transmission Service paid for by the External Market Buyer. Further delivery of such energy shall be the responsibility of the External Market Buyer.

1.7.10 Other Transactions.

(a) Bilateral Transactions.

(i) In addition to transactions in the PJM Interchange Energy Market, Market Participants may enter into bilateral contracts for the purchase or sale of electric energy to or from each other or any other entity, subject to the obligations of Market Participants to make Generation Capacity Resources available for dispatch by the Office of the Interconnection. Such bilateral contracts shall be for the physical transfer of energy to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its eSchedules and Enhanced Energy Scheduler tools.

(ii) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of energy to a Market Participant inside the PJM Region, title to the energy that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and the further transmission of the energy or further sale of the energy into the PJM Interchange Energy Market shall be transacted by the buyer under the bilateral contract. With respect to all bilateral contracts for the physical transfer of energy to an entity outside the PJM Region, title to the energy shall pass to the buyer at the border of the PJM Region and shall be delivered to the border using transmission service. In no event shall the purchase and sale of energy between Market Participants under a bilateral contract constitute a transaction in the PJM Interchange Energy Market or be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

(iii) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of energy reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the megawatt hours of such reported transactions to amounts reflecting the expected load and other physical delivery obligations of the buyer under the bilateral contract.

(iv) All payments and related charges for the energy associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. 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 a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

(v) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any Spot Market Backup used to meet the bilateral contract seller's obligation to deliver energy under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new eSchedules or Enhanced Energy Scheduler reporting by the Market Participant and (ii) terminate all of the Market Participant's eSchedules and Enhanced Energy Schedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the eSchedules and Enhanced Energy Schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection. PJMSettlement shall assign its claims against a seller with respect to a seller's nonpayment for Spot Market Backup to a buyer the extent that the buyer has made an indemnification payment to PJMSettlement with respect to the seller's nonpayment.

(vi) Bilateral contracts that do not contemplate the physical transfer of energy to or from a Market Participant are not subject to this Schedule, shall not be reported to and coordinated with the Office of the Interconnection, and shall not in any way constitute a transaction in the PJM Interchange Energy Market.

(b) Market Participants shall have Spot Market Backup with respect to all bilateral transactions that contemplate the physical transfer of energy to or from a Market Participant, that are not dynamically scheduled pursuant to Section 1.12 and that are curtailed or interrupted for any reason (except for curtailments or interruptions through active load management for load located within the PJM Region).

(c) To the extent the Office of the Interconnection dispatches a Generating Market Buyer's generation resources, such Generating Market Buyer may elect to net the output of such resources against its hourly Equivalent Load. Such a Generating Market Buyer shall be deemed a buyer from the PJM Interchange Energy Market to the extent of its PJM Interchange Imports, and shall be deemed a seller to the PJM Interchange Energy Market to the extent of its PJM Interchange Exports.

(d) A Market Seller may self-supply Station Power for its generation facility in accordance with the following provisions:

(i) A Market Seller may self-supply Station Power for its generation facility during any month (1) when the net output of such facility is positive, or (2) when the net output of such facility is negative and the Market Seller during the same month has available at other of its generation facilities positive net output in an amount at least sufficient to offset fully such negative net output. For purposes of this subsection (d), "net output" of a generation facility during any month means the facility's gross energy output, less the Station Power requirements of such facility, during that month. The determination of a generation facility's or a Market Seller's monthly net output under this subsection (d) will apply only to determine whether the Market Seller self-supplied Station Power during the month and will not affect the price of energy sold or consumed by the Market Seller at any bus during any hour during the month. For each hour when a Market Seller has positive net output and delivers energy into the Transmission System, it will be paid the LMP at its bus for that hour for all of the energy delivered. Conversely, for each hour when a Market Seller has negative net output and has received Station Power from the Transmission System, it will pay the LMP at its bus for that hour for all of the energy consumed.

(ii) Transmission Provider will determine the extent to which each affected Market Seller during the month self-supplied its Station Power requirements or obtained Station Power from third-party providers (including affiliates) and will incorporate that determination in its accounting and billing for the month. In the event that a Market Seller self-supplies Station Power during any month in the manner described in subsection (1) of subsection (d)(i) above, Market Seller will not use, and will not incur any charges for, transmission service. In the event, and to the extent, that a Market Seller self-supplies Station Power during any month in the manner described in subsection (2) of subsection (d)(i) above (hereafter referred to as "remote self-supply of Station Power"), Market Seller shall use and pay for transmission service for the transmission of energy in an amount equal to the facility's negative net output from Market Seller's generation facility(ies) having positive net output. Unless the Market Seller makes other arrangements with Transmission Provider in advance, such transmission service shall be provided under Part II of the PJM Tariff and shall be charged the hourly rate under Schedule 8 of the PJM Tariff for Non-Firm Point-to-Point Transmission Service with an election to pay congestion charges, provided, however, that no reservation shall be necessary for such transmission service and the terms and charges under Schedules 1, 1A, 2 through 6, 9 and 10 of the PJM Tariff shall not apply to such service. The amount of energy that a Market Seller transmits in conjunction with remote self-supply of Station Power will not be affected by any other sales, purchases, or transmission of capacity or energy by or for such Market Seller under any other provisions of the PJM Tariff.

(iii) A Market Seller may self-supply Station Power from its generation facilities located outside of the PJM Region during any month only if such generation facilities in fact run during such month and Market Seller separately has reserved transmission service and scheduled delivery of the energy from such resource in advance into the PJM Region.

1.7.11 Emergencies.

(a) The Office of the Interconnection, with the assistance of the Members' dispatchers as it may request, shall be responsible for monitoring the operation of the PJM Region, for declaring the existence of an Emergency, and for directing the operations of Market Participants as necessary to manage, alleviate or end an Emergency. The standards, policies and procedures of the Office of the Interconnection for declaring the existence of an Emergency, including but not limited to a Minimum Generation Emergency, and for managing, alleviating or ending an Emergency, shall apply to all Members on a non-discriminatory basis. Actions by the Office of the Interconnection and the Market Participants shall be carried out in accordance with this Agreement, the NERC Operating Policies, Applicable Regional Reliability Council reliability principles and standards, Good Utility Practice, and the PJM Manuals. A declaration that an Emergency exists or is likely to exist by the Office of the Interconnection shall be binding on all Market Participants until the Office of the Interconnection announces that the actual or threatened Emergency no longer exists. Consistent with existing contracts, all Market Participants shall comply with all directions from the Office of the Interconnection for the purpose of managing, alleviating or ending an Emergency. The Market Participants shall authorize the Office of the Interconnection and PJMSettlement to purchase or sell energy on their behalf to meet an Emergency, and otherwise to implement agreements with other Control Areas interconnected with the PJM Region for the mutual provision of service to meet an Emergency, in accordance with this Agreement.

(b) To the extent load must be shed to alleviate an Emergency in a Control Zone, the Office of the Interconnection shall, to the maximum extent practicable, direct the shedding of load within such Control Zone. The Office of the Interconnection may shed load in one Control Zone to alleviate an Emergency in another Control Zone under its control only as necessary after having first shed load to the maximum extent practicable in the Control Zone experiencing the Emergency and only to the extent that PJM supports other control areas (not under its control) in those situations where load shedding would be necessary, such as to prevent isolation of facilities within the Eastern Interconnection, to prevent voltage collapse, or to restore system frequency following a system collapse; provided, however, that the Office of the Interconnection may not order a manual load dump in a Control Zone solely to address capacity deficiencies in another Control Zone. This subsection shall be implemented consistent with North American Electric Reliability Council and applicable reliability council standards.

1.7.12 Fees and Charges.

Each Market Participant, except for Special Members, shall pay all fees and charges of the Office of the Interconnection for operation of the PJM Interchange Energy Market as determined

by and allocated to the Market Participant by the Office of the Interconnection in accordance with Schedule 3.

1.7.13 Relationship to the PJM Region.

The PJM Interchange Energy Market operates within and subject to the requirements for the operation of the PJM Region.

1.7.14 PJM Manuals.

The Office of the Interconnection shall be responsible for maintaining, updating, and promulgating the PJM Manuals as they relate to the operation of the PJM Interchange Energy Market. The PJM Manuals, as they relate to the operation of the PJM Interchange Energy Market, shall conform and comply with this Agreement, NERC operating policies, and Applicable Regional Reliability Council reliability principles, guidelines and standards, and shall be designed to facilitate administration of an efficient energy market within industry reliability standards and the physical capabilities of the PJM Region.

1.7.15 Corrective Action.

Consistent with Good Utility Practice, the Office of the Interconnection shall be authorized to direct or coordinate corrective action, whether or not specified in the PJM Manuals, as necessary to alleviate unusual conditions that threaten the integrity or reliability of the PJM Region, or the regional power system.

1.7.16 Recording.

Subject to the requirements of applicable State or federal law, all voice communications with the Office of the Interconnection Control Center may be recorded by the Office of the Interconnection and any Market Participant communicating with the Office of the Interconnection Control Center, and each Market Participant hereby consents to such recording.

1.7.17 Operating Reserves.

(a) The following procedures shall apply to any generation unit subject to the dispatch of the Office of the Interconnection for which construction commenced before July 9, 1996, or any Demand Resource subject to the dispatch of the Office of the Interconnection.

(b) The Office of the Interconnection shall schedule to the Operating Reserve and load-following objectives of the Control Zones of the PJM Region and the PJM Interchange Energy Market in scheduling generation resources and/or Demand Resources pursuant to this Schedule. A table of Operating Reserve objectives for each Control Zone is calculated and published annually in the PJM Manuals. Reserve levels are probabilistically determined based on the season's historical load forecasting error and forced outage rates.

(c) Nuclear generation resources shall not be eligible for Operating Reserve payments unless: 1) the Office of the Interconnection directs such resources to reduce output, in which case, such units shall be compensated in accordance with section 3.2.3(f) of this Schedule; or 2) the resource submits a request for a risk premium to the Market Monitoring Unit under the procedures specified in Section II.B of Attachment M - Appendix. A nuclear generation resource (i) must submit a risk premium consistent with its agreement under such process, or, (ii) if it has not agreed with the Market Monitoring Unit on an appropriate risk premium, may submit its own determination of an appropriate risk premium to the Office of the Interconnection, subject to acceptance by the Office of the Interconnection, with or without prior approval from the Commission.

(d) PJMSettlement shall be the Counterparty to the purchases and sales of Operating Reserve in the PJM Interchange Energy Market.

1.7.18 Regulation.

(a) Regulation to meet the Regulation objective of each Regulation Zone shall be supplied from generation resources and/or Demand Resources located within the metered electrical boundaries of such Regulation Zone. Generating Market Buyers, and Market Sellers offering Regulation, shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the PJM Manuals.

(b) The Office of the Interconnection shall obtain and maintain for each Regulation Zone an amount of Regulation equal to the Regulation objective for such Regulation Zone as specified in the PJM Manuals.

(c) The Regulation range of a generation unit or Demand Resource shall be at least twice the amount of Regulation assigned as described in the PJM Manuals.

(d) A resource capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced by at least twice the amount of the Regulation provided with consideration of the Regulation limits of that resource, as specified in the PJM Manuals.

(e) Qualified Regulation must satisfy the verification tests described in the PJM Manuals.

1.7.19 Ramping.

A generator dispatched by the Office of the Interconnection pursuant to a control signal appropriate to increase or decrease the generator's megawatt output level shall be able to change output at the ramping rate specified in the Offer Data submitted to the Office of the Interconnection for that generator.

1.7.19A Synchronized Reserve.

(a) Synchronized Reserve shall be supplied from generation resources and/or Demand Resources located within the metered boundaries of the PJM Region. Generating Market

Buyers, and Market Sellers offering Synchronized Reserve shall comply with applicable standards and requirements for Synchronized Reserve capability and dispatch specified in the PJM Manuals.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone an amount of *Primary and* Synchronized Reserve equal to the *respective Primary and* Synchronized Reserve objectives for such Reserve Zone, as specified in the PJM Manuals.

(c) The Synchronized Reserve capability of a generation resource and Demand Resource shall be the increase in energy output or load reduction achievable by the generation resource and Demand Resource within a continuous 10-minute period.

(d) A generation unit capable of automatic energy dispatch that also is providing Synchronized Reserve shall have its energy dispatch range reduced by the amount of the Synchronized Reserve provided. The amount of Synchronized Reserve provided by a generation unit shall serve to redefine the Normal Maximum Generation energy limit of that generation unit in that the amount of Synchronized Reserve provided shall be subtracted from its Normal Maximum Generation energy limit.

1.7.19A.01 Non-Synchronized Reserve.

(a) Non-Synchronized Reserve shall be supplied from generation resources and/or Demand Resources located within the metered boundaries of the PJM Region. Generating Market Buyers and Market Sellers offering Non-Synchronized Reserve shall comply with applicable standards and requirements for Non-Synchronized Reserve capability and dispatch specified in the PJM Manuals.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone an amount of Non-Synchronized Reserve such that the sum of the Synchronized Reserve and Non-Synchronized Reserve meets the Primary Reserve objective for such Reserve Zone, as specified in the PJM Manuals.

(c) The Non-Synchronized Reserve capability of a generation resource and Demand Resource shall be the increase in energy output or load reduction achievable by the generation resource and Demand Resource within a continuous 10-minute period provided that the resource is not synchronized to the system at the initiation of the response.

1.7.19B Bilateral Transactions Regarding Regulation, Synchronized Reserve and Day-ahead Scheduling Reserves.

(a) In addition to transactions in the Regulation market, Synchronized Reserve market, and Day-ahead Scheduling Reserves Market, Market Participants may enter into bilateral contracts for the purchase or sale of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from each other or any other entity. Such bilateral contracts shall be for the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or

from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its eMarket tools.

(b) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to a Market Participant in the PJM Region, title to the product that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and any further transactions associated with such products or further sale of such Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves in the markets for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves, respectively, shall be transacted by the buyer under the bilateral contract. In no event shall the purchase and sale of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves between Market Participants under a bilateral contract constitute a transaction in PJM's markets for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves, or otherwise construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

(c) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the amounts of such reported transactions to amounts reflecting the expected requirements for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves of the buyer pursuant to such bilateral contracts.

(d) All payments and related charges for the Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection. The LLC, PJM Settlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

(e) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any purchases by the seller under the bilateral contract in the markets for Regulations, Synchronized Reserve, or Day-ahead Scheduling Reserves used to meet the bilateral contract seller's obligation to deliver Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new eMarket reporting by the Market Participant and (ii) terminate all of the Market Participant's reporting of eMarkets schedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the reported eMarkets schedules associated with

bilateral contracts between buyer and seller previously reported to the Office of the Interconnection.

(f) Market Participants shall purchase Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves from PJM's markets for Regulation, Synchronized Reserve, Day-ahead Scheduling Reserves, in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason, with respect to all bilateral transactions that contemplate the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from a Market Participant.

1.7.20 Communication and Operating Requirements.

(a) Market Participants. Each Market Participant shall have, or shall arrange to have, its transactions in the PJM Interchange Energy Market subject to control by a Market Operations Center, with staffing and communications systems capable of real-time communication with the Office of the Interconnection during normal and Emergency conditions and of control of the Market Participant's relevant load or facilities sufficient to meet the requirements of the Market Participant's transactions with the PJM Interchange Energy Market, including but not limited to the following requirements as applicable.

(b) Market Sellers selling from generation resources and/or Demand Resources within the PJM Region shall: report to the Office of the Interconnection sources of energy and Demand Resources available for operation; supply to the Office of the Interconnection all applicable Offer Data; report to the Office of the Interconnection generation resources that are self-scheduled; with respect to generation resources, report to the Office of the Interconnection bilateral sales transactions to buyers not within the PJM Region; confirm to the Office of the Interconnection bilateral sales to Market Buyers within the PJM Region; respond to the Office of the Interconnection's directives to start, shutdown or change output levels of generation units, or change scheduled voltages or reactive output levels of generation units, or reduce load from Demand Resources; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, generating equipment and Demand Resources are operated with control equipment functioning as specified in the PJM Manuals.

(c) Market Sellers selling from generation resources outside the PJM Region shall: provide to the Office of the Interconnection all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to Office of the Interconnection directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the Market Seller's Control Area.

(d) Market Participants that are Load Serving Entities or purchasing on behalf of Load Serving Entities shall: respond to Office of the Interconnection directives for load management steps; report to the Office of the Interconnection Generation Capacity Resources to satisfy capacity obligations that are available for pool operation; report to the Office of the Interconnection all bilateral purchase transactions; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(e) Market Participants that are not Load Serving Entities or purchasing on behalf of Load Serving Entities shall: provide to the Office of the Interconnection requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the PJM Interchange Energy Market, along with Dispatch Rate levels above which it does not desire to purchase; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(f) Economic Load Response Participants are responsible for maintaining demand reduction information, including the amount and price at which demand may be reduced. The Economic Load Response Participant shall provide this information to the Office of the Interconnection by posting it on the Load Response Program Registration link of the PJM website as required by the PJM Manuals. The Economic Load Response Participant shall notify the Office of the Interconnection of a demand reduction concurrent with, or prior to, the beginning of such demand reduction in accordance with the PJM Manuals. In the event that an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer that would affect a relevant Customer Baseline Load as required by the PJM Manuals.

(g) PRD Providers shall be responsible for ensuring automated reductions to their Price Responsive Demand in response to price in accordance with their PRD Curves submitted to the Office of the Interconnection.

1.10 Scheduling.

1.10.1 General.

(a) The Office of the Interconnection shall administer scheduling processes to implement a Day-ahead Energy Market and a Real-time Energy Market. PJMSettlement shall be the Counterparty to the purchases and sales of energy that clear the Day-ahead Energy Market and the Real-time Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a Generating Market Buyer's self-schedule or self-supply of its generation resources up to that Generating Market Buyer's Equivalent Load.

(b) The Day-ahead Energy Market shall enable Market Participants to purchase and sell energy through the PJM Interchange Energy Market at Day-ahead Prices and enable Transmission Customers to reserve transmission service with Transmission Congestion Charges and Transmission Loss Charges based on locational differences in Day-ahead Prices. Up-To Congestion transactions submitted in the Day-ahead Energy Market shall not require transmission service and Transmission Customers shall not reserve transmission service for such transactions. Market Participants whose purchases and sales, and Transmission Customers whose transmission uses are scheduled in the Day-ahead Energy Market, shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, at the applicable Day-ahead Prices for the amounts scheduled.

(c) In the Real-time Energy Market, Market Participants that deviate from the amounts of energy purchases or sales, or Transmission Customers that deviate from the transmission uses, scheduled in the Day-ahead Energy Market shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling shall be conducted as specified below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM Manuals.

1.10.1A Day-ahead Energy Market Scheduling.

The following actions shall occur not later than 12:00 noon on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the Office of the Interconnection in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Schedule.

(a) Each Market Participant may submit to the Office of the Interconnection specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the PJM Manuals. Each Market Buyer shall inform the Office of the Interconnection of the prices, if any, at which it desires not to include its load in the Day-ahead Energy Market rather than pay the Day-ahead Price. PRD Providers that have committed Price Responsive Demand in accordance with the Reliability Assurance Agreement shall submit to the Office of the Interconnection, in accordance with procedures specified in the PJM Manuals, any desired updates to their previously submitted PRD Curves, provided that such updates are consistent with their Price Responsive Demand commitments, and provided further that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue may only submit PRD Curves for the Real-time Energy Market. Price Responsive Demand that has been committed in accordance with the Reliability Assurance Agreement shall be presumed available for the next Operating Day in accordance with the most recently submitted PRD Curve unless the PRD Curve is updated to indicate otherwise. PRD Providers may also submit PRD Curves for any Price Responsive Demand that is not committed in accordance with the Reliability Assurance Agreement; provided that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue may only submit PRD Curves for the Real-time Energy Market. All PRD Curves shall be on a PRD Substation basis, and shall specify the maximum time period required to implement load reductions.

(b) Each Generating Market Buyer shall submit to the Office of the Interconnection: (i) hourly schedules for resource increments, including hydropower units, self-scheduled by the Market Buyer to meet its Equivalent Load; and (ii) the Dispatch Rate at which each such self-scheduled resource will disconnect or reduce output, or confirmation of the Market Buyer's intent not to reduce output.

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

scheduled bilateral transaction. Scheduling of bilateral transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

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

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

iii) In addition to the foregoing schedules for bilateral transactions, Market Participants shall submit confirmations of each scheduled bilateral transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(d) Market Sellers wishing to sell into the Day-ahead Energy Market shall submit offers for the supply of energy (including energy from hydropower units), demand reductions, Regulation, Operating Reserves or other services for the following Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Attachment DD of the PJM Tariff, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. *Any offer not designated as a Maximum Emergency Offer shall be considered available for scheduling and dispatch under both Emergency and non-Emergency conditions. Offers may only be designated as Maximum Emergency Offers to the extent that the Generation Capacity Resource falls into at least one of the following categories:*

i) Environmental limits. If the resource has a limit on its run hours imposed by a federal, state or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited to operating only during declared PJM capacity emergencies by a governmental authority.

ii) Fuel limits. If physical events beyond the control of the resource owner result in the temporary interruption of fuel supply and there is limited on-site fuel storage. A fuel supplier's exercise of a contractual right to interrupt supply or delivery under an interruptible service agreement shall not qualify as an event beyond the control of the resource owner.

iii) Temporary emergency conditions at the unit. If temporary emergency physical conditions at the resource significantly limit its availability.

iv) Temporary megawatt additions. If a resource can provide additional megawatts on a temporary basis by oil topping, boiler over-pressure, or similar techniques and such megawatts are not ordinarily otherwise available.

The submission of offers for resource increments that have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, and PJM Manuals, as applicable. Energy offered from generation resources that have not cleared a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region. The foregoing offers:

i) Shall specify the Generation Capacity Resource or Demand Resource and energy or demand reduction amount, respectively, for each hour in the offer period, and the minimum run time for generation resources and minimum down time for Demand Resources;

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

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

iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;

v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with a second schedule applicable if accepted after the foregoing deadline;

vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer, which offer shall remain open through the Operating Day for which the offer is submitted;

vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or

prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day; and

viii) Shall not exceed an energy offer price of $1,000/megawatt-*hour for all generation resources and Demand Resources that have cleared a Base Residual Auction or an Incremental Auction.*

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation that shall specify the megawatt of Regulation being offered, which must equal or exceed 0.1 megawatts, the Regulation Zone for which such regulation is offered, the price of the capability offer in dollars per MW, the price of the performance offer in Dollars per change in MW, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the resource's opportunity costs. The total of the performance offer multiplied by the historical average mileage used in the market clearing plus the capability offer shall not exceed $100 per MWh in the case of Regulation offered for all Regulation Zones. In addition to any market-based offer for Regulation, the Market Seller also shall submit a cost-based offer. A cost-based offer must be in the form specified in the PJM Manuals and consist of the following components as well as any other components specified in the PJM Manuals:

i. The costs (in $/MW) of the fuel cost increase due to the heat rate increase resulting from operating a unit at lower megawatt output incurred from the provision of Regulation;

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

iii. An adder of up to $12.00 per megawatt of Regulation provided applied to the capability offer.

Qualified Regulation capability must satisfy the measurement and verification tests specified in the PJM Manuals.

(f) Each Market Seller owning or controlling the output of a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative shall submit a forecast of the availability of each such Generation Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with start-up and no-load fees, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours.

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

(h) The Office of the Interconnection shall post the total hourly loads scheduled in the Day-ahead Energy Market, as well as, its estimate of the combined hourly load of the Market Buyers for the next four days, and peak load forecasts for an additional three days.

(i) Except for Economic Load Response Participants, all Market Participants may submit Increment Bids and/or Decrement Bids that apply to the Day-ahead Energy Market only. Such bids must comply with the requirements set forth in the PJM Manuals and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-ahead Energy Market. The Office of the Interconnection may require that a market participant shall not submit in excess of 3000 bid/offer segments in the Day-ahead Energy Market, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to 10:00 a.m. EPT on the day that the Day-ahead Energy Market will clear. For purposes of this provision, a bid/offer segment is each pairing of price and megawatt quantity submitted as part of an Increment Bid or Decrement Bid.

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

(k) An Economic Load Response Participant that wishes to participate in the Day-ahead Energy Market by reducing demand shall submit an offer to reduce demand to the Office of the Interconnection. The offer must equal or exceed 0.1 megawatts, and the offer shall specify: (i) the amount of the offered curtailment in minimum increments of .1 megawatts: (ii) the Day-ahead Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, start-up costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum of number of contiguous hours for which the load reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs).

(l) Market Sellers owning or controlling the output of a Demand Resource that was committed in an FRR Capacity Plan, self-supplied or offered and cleared in the Base Residual Auction or one of the Incremental Auctions, or owning or controlling the output of an ILR resource which was certified as specified in Attachment DD of the PJM Tariff, may submit demand reduction bids for the available load reduction capability of the Demand Resource or ILR resource. The submission of demand reduction bids for resource increments that have not cleared in the Base Residual Auction or in one of the Incremental Auctions, or for ILR resources that were not certified, or were not committed in an FRR Capacity Plan, shall be optional, but

any such bids must contain the information specified in the PJM Economic Load Response Program to be included in such bids. A Demand Resource that was committed in an FRR Capacity Plan, self-supplied or offered and cleared in a Base Residual Auction or an Incremental Auction may submit a demand reduction bid in the Day-ahead Energy Market as specified in the Economic Load Response Program, provided however, that in the event of an Emergency, PJM shall require Demand Resources and ILR resources to reduce load notwithstanding that the Zonal LMP at the time such Emergency is declared is below the price identified in the demand reduction bid.

(m) Market Sellers that wish to make Day-ahead Scheduling Reserves Resources available to sell Day-ahead Scheduling Reserves shall submit offers, each of which must equal or exceed 0.1 megawatts, in the Day-ahead Scheduling Reserves Market specifying: 1) the price of the offer in dollars per megawatt hour; and 2) such other information specified by the Office of the Interconnection as may be necessary to determine any relevant opportunity costs for the resource(s). The foregoing notwithstanding, to qualify to submit offers pursuant to this section, the Day-ahead Scheduling Reserves Resources shall submit energy offers in the Day-ahead Energy Market including start-up and shut-down costs for generation resource and Demand Resources, respectively, and all generation resources that are capable of providing Day-ahead Scheduling Reserves that a particular resource can provide that service. The MW quantity of Day-ahead Scheduling Reserves that a particular resource can provide in a given hour will be determined based on the energy Offer Data submitted in the Day-ahead Energy Market, as detailed in the PJM Manuals.

1.10.2 Pool-scheduled Resources.

Pool-scheduled resources are those resources for which Market Participants submitted offers to sell energy in the Day-ahead Energy Market and offers to reduce demand in the Day-ahead Energy Market, which the Office of the Interconnection scheduled in the Day-ahead Energy Market as well as generators committed by the Office of the Interconnection subsequent to the Day-ahead Energy Market. Such resources shall be committed to provide energy in the real-time dispatch unless the schedules for such units are revised pursuant to Sections 1.10.9 or 1.11. Pool-scheduled resources shall be governed by the following principles and procedures.

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, start-up, no-load and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in Section 1.10.1A.

(b) A resource that is scheduled by a Market Participant to support a bilateral sale, or that is self-scheduled by a Generating Market Buyer, shall not be selected by the Office of the Interconnection as a pool-scheduled resource except in an Emergency.

(c) Market Sellers offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the Office of the Interconnection that is sufficient to enable the Office of the Interconnection to determine the available operating hours of such facilities.

(d) The Market Seller of a resource selected as a pool-scheduled resource shall receive payments or credits for energy, demand reductions or related services, or for start-up and no-load fees, from the Office of the Interconnection on behalf of the Market Buyers in accordance with Section 3 of this Schedule 1. Alternatively, the Market Seller shall receive, in lieu of start-up and no-load fees, its actual costs incurred, if any, up to a cap of the resource's start-up cost, if the Office of the Interconnection cancels its selection of the resource as a pool-scheduled resource and so notifies the Market Seller before the resource is synchronized.

(e) Market Participants shall make available their pool-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone.

(f) Economic Load Response Participants offering to reduce demand shall specify: (i) the amount of the offered curtailment, which offer must equal or exceed 0.1 megawatts, in minimum increments of .1 megawatts; (ii) the real-time Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, shut-down costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum number of contiguous hours for which the load reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Real-time Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs). Economic Load Response Participants offering to reduce demand shall also indicate the hours that the demand reduction is not available.

1.10.3 Self-scheduled Resources.

Self-scheduled resources shall be governed by the following principles and procedures.

(a) Each Generating Market Buyer shall use all reasonable efforts, consistent with Good Utility Practice, not to self-schedule resources in excess of its Equivalent Load.

(b) The offered prices of resources that are self-scheduled, or otherwise not following the dispatch orders of the Office of the Interconnection, shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.

(c) Market Participants shall make available their self-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone, by submitting an offer as to such resources.

(d) A Market Participant self-scheduling a resource in the Day-ahead Energy Market that does not deliver the energy in the Real-time Energy Market, shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

1.10.4 Capacity Resources.

(a) A Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that is selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection. Such a Generation Capacity Resource that does not deliver energy as scheduled shall be deemed to have experienced a Generator Forced Outage to the extent of such energy not delivered. A Market Participant offering such Generation Capacity Resource in the Day-ahead Energy Market shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Energy from a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that has not been scheduled in the Day-ahead Energy Market may be sold on a bilateral basis by the Market Seller, may be self-scheduled, or may be offered for dispatch during the Operating Day in accordance with the procedures specified in this Schedule. Such a Generation Capacity Resource that has not been scheduled in the Day-ahead Energy Market and that has been sold on a bilateral basis must be made available upon request to the Office of the Interconnection for scheduling and dispatch during the Operating Day if the Office of the Interconnection declares a Maximum Generation Emergency. Any such resource so scheduled and dispatched shall receive the applicable Real-time Price for energy delivered.

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

1.10.5 External Resources.

(a) External Resources may submit offers to the PJM Interchange Energy Market, in accordance with the day-ahead and real-time scheduling processes specified above. An External Resource selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection, and except as specified below shall be compensated on the same basis as other pool-scheduled resources. External Resources that are not capable of dynamic dispatch shall, if selected by the Office of the Interconnection on the basis of the Market Seller's Offer Data, be block loaded on an hourly scheduled basis. Market Sellers shall offer External Resources to the PJM Interchange Energy Market on either a resource-specific or an aggregated resource basis. A Market Participant whose pool-scheduled resource does not deliver the energy scheduled in the Day-ahead Energy Market shall replace such energy not delivered as scheduled in the Day-ahead Energy Market with energy from the PJM Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Offers for External Resources from an aggregation of two or more generating units shall so indicate, and shall specify, in accordance with the Offer Data requirements specified by the Office of the Interconnection: (i) energy prices; (ii) hours of energy availability; (iii) a minimum dispatch level; (iv) a maximum dispatch level; and (v) unless such information has previously been made available to the Office of the Interconnection, sufficient information, as specified in the PJM Manuals, to enable the Office of the Interconnection to model the flow into the PJM Region of any energy from the External Resources scheduled in accordance with the Offer Data.

(c) Offers for External Resources on a resource-specific basis shall specify the resource being offered, along with the information specified in the Offer Data as applicable.

1.10.6 External Market Buyers.

(a) Deliveries to an External Market Buyer not subject to dynamic dispatch by the Office of the Interconnection shall be delivered on a block loaded basis to the bus or buses at the electrical boundaries of the PJM Region, or in such area with respect to an External Market Buyer's load within such area not served by Network Service, at which the energy is delivered to or for the External Market Buyer. External Market Buyers shall be charged (which charge may be positive or negative) at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing bus or buses.

(b) An External Market Buyer's hourly schedules for energy purchased from the PJM Interchange Energy Market shall conform to the ramping and other applicable requirements of the interconnection agreement between the PJM Region and the Control Area to which, whether as an intermediate or final point of delivery, the purchased energy will initially be delivered.

(c) The Office of the Interconnection shall curtail deliveries to an External Market Buyer if necessary to maintain appropriate reserve levels for a Control Zone as defined in the PJM Manuals, or to avoid shedding load in such Control Zone.

1.10.6A Transmission Loading Relief Customers.

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

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

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

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

(c) In order to make elections under this Section 1.10.6A, an entity must (i) have met the creditworthiness standards established by the Office of the Interconnection or provided a letter of

credit or other form of security acceptable to the Office of the Interconnection, and (ii) have executed either the Agreement, a Service Agreement under the PJM Tariff, or other agreement committing to pay all Transmission Congestion Charges incurred under this Section.

1.10.7 Bilateral Transactions.

Bilateral transactions as to which the parties have notified the Office of the Interconnection by the deadline specified in Section 1.10.1A that they elect not to be included in the Day-ahead Energy Market and that they are not willing to incur Transmission Congestion Charges in the Real-time Energy Market shall be curtailed by the Office of the Interconnection as necessary to reduce or alleviate transmission congestion. Bilateral transactions that were not included in the Day-ahead Energy Market and that are willing to incur congestion charges and bilateral transactions that were accepted in the Day-ahead Energy Market shall continue to be implemented during periods of congestion, except as may be necessary to respond to Emergencies.

1.10.8 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers and PRD Curves properly submitted by Load Serving Entities for the Price Responsive Demand loads they serve; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv) the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) Not earlier than 4:00 p.m. of the day before each Operating Day, or such other deadline as may be specified by the Office of the Interconnection in the PJM Manuals, the Office of the Interconnection shall: (i) post the aggregate Day-ahead Energy Market results; (ii) post the Day-

ahead Prices; and (iii) inform the Market Sellers, Market Buyers, and Economic Load Response Participants of their scheduled injections, withdrawals, and demand reductions respectively.

(c) Following posting of the information specified in Section 1.10.8(b), the Office of the Interconnection shall revise its schedule of generation resources to reflect updated projections of load, conditions affecting electric system operations in the PJM Region, the availability of and constraints on limited energy and other resources, transmission constraints, and other relevant factors.

(d) Market Buyers shall pay PJMSettlement and Market Sellers shall be paid by PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the offer that set the Day-ahead Price is positive. Market Buyers shall be paid by PJMSettlement and Market Sellers shall pay PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the offer that set the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Section 3.3A of this Schedule.

(e) If the Office of the Interconnection discovers an error in prices and/or cleared quantities in the Day-ahead Energy Market, Real-time Energy Market, Ancillary Services Markets or Day Ahead Scheduling Reserve Market after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 12:00 p.m. of the second business day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the second business day following the initial publication of the results for the Day-ahead Scheduling Reserve Market and Day-ahead Energy Market. After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the fifth business day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the fifth business day following the initial publication of the results in the Day-ahead Scheduling Reserve Market and the Day-ahead Energy Market. Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating Day for the Ancillary Services Markets, Day-ahead Energy Market and Real-time Energy Market, and no later than 5:00 p.m. of the tenth calendar day following the initial publication of the results in the Day-ahead Scheduling Reserve Market. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced market results are under publicly noticed review by the FERC.

(f) Consistent with Section 18.17.1 of the PJM Operating Agreement, and notwithstanding anything to the contrary in the Operating Agreement or in the PJM Tariff, to allow the tracking of Market Participants' non-aggregated bids and offers over time as required by FERC Order No. 719, the Office of the Interconnection shall post on its Web site the non-aggregated bid data and Offer Data submitted by Market Participants (for participation in the PJM Interchange Energy

Market) approximately four months after the bid or offer was submitted to the Office of the Interconnection.

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, a generation rebidding period shall exist from 4:00 p.m. to 6:00 p.m. on the day before each Operating Day. During the rebidding period, Market Participants may submit revisions to generation Offer Data for any generation resource that was not selected as a pool-scheduled resource in the Day-ahead Energy Market. Adjustments to Day-ahead Energy Markets shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 60 minutes prior to the hour in which the adjustment is to take effect, as follows:

i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;

ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or

iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or

iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any start-up fee.

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

(d) An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase in the Day-ahead Energy Market by notifying the Office of the Interconnection of the adjustment in deliveries not later than 60 minutes prior to the hour in which the adjustment is

to take effect, but any such adjustment shall not affect the obligation of the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(e) For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section 1.10, the Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules for the hour.

1.11 Dispatch.

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

1.11.1 Resource Output.

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

1.11.2 Operating Basis.

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

1.11.3 Pool-dispatched Resources.

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

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

1.11.3A Maximum Generation Emergency.

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

1.11.4 Regulation.

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

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

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

1.11.4A Synchronized Reserve.

(a) A Market Buyer may satisfy its Synchronized Reserve Obligation from its own generation resources and/or Demand Resources capable of providing Synchronized Reserve, by contractual arrangements with other Market Participants able to provide Synchronized Reserve,

or by purchases from the PJM Synchronized Reserve Market at the rates set forth in Section 3.2.3A. PJMSettlement shall be the Counterparty to the purchases and sales of Synchronized Reserve in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Synchronized Reserve Obligation.

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

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

1.11.4B Non-Synchronized Reserve.

(a) A Market Buyer may satisfy its Non-Synchronized Reserve Obligation from its own generation resources and/or Demand Resources capable of providing Non-Synchronized Reserve, by contractual arrangements with other Market Participants able to provide Non-Synchronized Reserve, or by purchases from the PJM Non-Synchronized Reserve Market at the rates set forth in Section 3.2.3A.001.

(b) The Office of the Interconnection shall obtain Non-Synchronized Reserve from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Demand Resources as needed to ensure the Primary Reserve requirement of each Reserve Zone of the PJM Region not otherwise satisfied by the Market Buyers. Resources offering to sell Non-Synchronized Reserve shall be selected to provide Non-Synchronized Reserve on the basis of each generation resource's and/or Demand Resource's estimated unit specific opportunity cost of the resource providing Non-Synchronized Reserve, and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Synchronized Reserve and other ancillary services. Estimated unit specific opportunity costs for generation resources shall be equal to the 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 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 Non-Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources will be zero.

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

1.11.5 PJM Open Access Same-time Information System.

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

2.2 General.

The Office of the Interconnection shall determine the least cost security-constrained dispatch, which is the least costly means of serving load *and meeting reserve requirements* at different locations in the PJM Region based on actual operating conditions existing on the power grid (including transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6) and on the prices at which Market Sellers have offered to supply energy and offers by Economic Load Response Participants to reduce demand that qualify to set Locational Marginal Prices in the PJM Interchange Energy Market. Locational Marginal Prices for the generation and load busses in the PJM Region, including interconnections with other Control Areas, will be calculated based on the actual economic dispatch and the prices of energy and demand reduction offers. The process for the determination of Locational Marginal Prices shall be as follows:

(a) To determine actual operating conditions on the power grid in the PJM Region, the Office of the Interconnection shall use a computer model of the interconnected grid that uses available metered inputs regarding generator output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network. The computer model employed for this purpose, referred to as the State Estimator program, is a standard industry tool and is described in Section 2.3 below. It will be used to obtain information regarding the output of generation supplying energy to the PJM Region, loads at busses in the PJM Region, transmission losses, and power flows on binding transmission constraints for use in the calculation of Locational Marginal Prices. Additional information used in the calculation, including Dispatch Rates and real time schedules for external transactions between PJM and other Control Areas and dispatch and pricing information from entities with whom PJM has executed a joint operating agreement, will be obtained from the Office of the Interconnection's dispatchers.

(b) Using the prices at which energy is offered by Market Sellers and demand reductions are offered by Economic Load Response Participants to the PJM Interchange Energy Market, the Office of the Interconnection shall determine the offers of energy and demand reductions that will be considered in the calculation of Locational Marginal Prices. As described in Section 2.4 below, every qualified offer for demand reduction and of energy by a Market Seller from resources that are *dispatched by* the Office of the Interconnection will be utilized in the calculation of Locational Marginal Prices, including, without limitation, qualified offers from Economic Load Response Participants in either the Day-Ahead or Real-Time Energy Markets that satisfy the Net Benefits Test. Offers of *economic load response* from Demand Resources in the Real-time Energy Market will not be eligible to set Locational Marginal Prices, unless metered directly by the Office of the Interconnection. *Offers of Full Program Option resources in the Emergency Load Response Program are eligible to set real time Locational Marginal Prices when the Office of the Interconnection has implemented Emergency procedures and such resources are required to reduce demand in the PJM Region, so long as sufficient data is available to accurately model the resources.*

(c) Based on the system conditions on the PJM power grid, determined as described in (a), and the eligible energy and demand reduction offers, determined as described in (b), the

Office of the Interconnection shall determine the least costly means of obtaining energy to serve the next increment of load at each bus in the PJM Region, in the manner described in Section 2.5 below. The result of that calculation shall be a set of Locational Marginal Prices based on the system conditions at the time.

2.3 Determination of System Conditions Using the State Estimator.

Power system operations, including, but not limited to, the determination of the least costly means of serving load *and meeting reserve requirements*, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In calculating Locational Marginal Prices, the Office of the Interconnection shall obtain a complete and consistent description of conditions on the electric network in the PJM Region by using the most recent power flow solution produced by the State Estimator *program and utilized in the PJM dispatch algorithm*, which *State Estimator program* is also used by the Office of the Interconnection for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available real-time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at busses for which real-time information is unavailable. The Office of the Interconnection shall obtain a State Estimator solution every five minutes, which shall provide the megawatt output of generators and the loads at busses in the PJM Region, transmission line losses, and actual flows or loadings on constrained transmission facilities. External transactions between PJM and other Control Areas shall be included in the Locational Marginal Price calculation on the basis of the real time transaction schedules implemented by the Office of the Interconnection's dispatcher.

2.4 Determination of Energy Offers Used in Calculating Real-time Prices.

(a) During the Operating Day, real-time Locational Marginal Prices derived in accordance with this Section shall be determined every five minutes and integrated hourly values of such determinations shall be the basis of sales and purchases of energy in the Real-time Energy Market and of Transmission Congestion Charges under the PJM Tariff not covered by the Day-ahead Energy Market.

(b) To determine the energy offers submitted to the PJM Interchange Energy Market that shall be used during the Operating Day to calculate the Real-time Prices, the Office of the Interconnection shall determine *the applicable marginal energy offer of the* resources *being dispatched by the Office of the Interconnection*. A resource shall be included in the calculation of Real-time Prices if the applicable *marginal energy offer of the* resource *being dispatched by the Office of the Interconnection* is less than or equal to the Dispatch Rate for the area of the PJM Region in which the resource is located.

(c) In determining whether a resource satisfies the condition described in (b), the Office of the Interconnection will determine the *applicable marginal* energy offer by comparing the *requested* megawatt output of the resource with the Market Seller's offer price curve. *T*he *applicable marginal* energy offer used in the calculation of Real-time Prices shall not exceed the applicable Dispatch Rate. Units that must be run for local area protection shall not be considered in the calculation of Real-time Prices.

2.5 Calculation of Real-time Prices.

(a) The Office of the Interconnection shall determine the least costly means of obtaining energy to serve the next increment of load (taking account of any applicable and available load reductions indicated on PRD Curves properly submitted by any PRD Provider) at each bus in the PJM Region represented in the State Estimator and each Interface Pricing Point between PJM and an adjacent Control Area, based on the system conditions described by the most recent power flow solution produced by the State Estimator program *and utilized in the PJM dispatch algorithm* and the energy offers that are the basis for the Day-ahead Energy Market, or that are determined to be eligible for consideration under Section 2.4 in connection with the real-time dispatch, as applicable. This calculation shall be made by applying *a real-time joint optimization of energy and reserves,* given actual system conditions, a set of energy offers, *a set of reserve offers, a set of Reserve Penalty Factors,* and any binding transmission constraints that may exist. In performing this calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a generation resource or decrease an increment of energy being consumed by a Demand Resource, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses. *The real-time Locational Marginal Prices at a bus shall be determined through the joint optimization based on the lowest marginal cost to serve the next increment of load at the bus taking into account the applicable reserve requirements, unit resource constraints, transmission constraints and marginal loss impact.*

(*b*) *If all reserve requirements in every modeled Reserve Zone can be met at prices less than or equal to the Reserve Penalty Factors for both the Synchronized Reserves and Non-synchronized Reserves, real-time Locational Marginal Prices shall be calculated as described in Section 2.5(a) above and no Reserve Penalty Factor shall apply beyond the normal lost opportunity costs incurred by the reserve requirements. When a reserve requirement cannot be met at a price less than or equal to the Reserve Penalty Factors associated with a Reserve Zone, the real-time Locational Marginal Prices shall be calculated by incorporating the applicable Reserve Penalty Factor for the deficient reserve product as the lost opportunity cost impact of the deficient reserve requirement, and the components of Locational Marginal Prices referenced in Section 2.5(a) above shall be calculated accordingly.*

(c) If the Office of the Interconnection has initiated in a Reserve Zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, Locational Marginal Prices for that Reserve Zone will be calculated including the Reserve Penalty Factors of all reserve products in that Reserve Zone.

(*d*) During the Operating Day, the calculation set forth in (a) shall be performed every five minutes, using the Office of the Interconnection's Locational Marginal Price program, producing a set of Real-time Prices based on system conditions during the preceding interval. The prices produced at five-minute intervals during an hour will be integrated to determine the Real-time Prices for that hour.

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 (g) of this section;the amounts, if any, described in subsection (e) of this section; and (iii) the Internal Market Buyer's pro rata share of any performance credits paid to regulating resources calculated in accordance with subsection (f) 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 such that the calculated credit for each increment of Regulation provided by each resource shall be the Regulation market-clearing price.

(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 (f) 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 from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.3.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation *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 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.

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

(e) 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.
(f) 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 (f) 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 capacity Regulation market-clearing price.

(g) 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.

(h) 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.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to section 1.10.1A(e) of this Schedule. A Regulation supplier fails the three-pivotal supplier test in any hour in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

(b) For the purposes of conducting the three-pivotal supplier test pursuant to this section, the following applies:

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region for which the 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.

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 unfor*e*seen Operating Reserve requirements that are not reflected in the Day-ahead Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load fees and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the

Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve credits, identified as RA Credits for Reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

(c) The sum of the foregoing credits calculated in accordance with Section 3.2.3(b) plus any unallocated charges from Section 3.2.3(h) and 5.1.7 and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program shall be the cost of Operating Reserves in the Day-ahead Energy Market.

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following segments: 1) the greater of their day-ahead schedules or minimum run time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or minimum run time (minimum down time for Demand Resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time (minimum down time for Demand Resources) and Segment 2 will include the remainder of the contiguous hours when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

Credits received pursuant to this section shall be equal to the positive difference between a resource's total offered price for start-up (shutdown costs for Demand Resources) and no-load fees and energy, determined on the basis of the resource's scheduled output, and the total value of the resource's energy as determined by the Real-time Energy Market and the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for segment 2 shall exclude start up (shutdown costs for Demand Resources) costs for generation resources.

Except as provided in Section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to Section 3.2.3(b) plus the resource's opportunity cost and less any amounts credited for Synchronized Reserve in excess of the Synchronized Reserve offer plus the resource's opportunity cost and less any amounts credited for providing Reactive Services as specified in Section 3.2.3B, and less any amounts for Day-

ahead Scheduling Reserve in excess of the Day-ahead Scheduling Reserve offer plus the resource's opportunity cost, shall be credited to the Market Seller.

Synchronized Reserve, *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 {(LMPDMW - AG) x (URTLMP – UB)}, where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

AG equals the actual hourly integrated output of the unit;

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

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

where URTLMP - UB shall not be negative.

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

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the

unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described above for a steam unit or combined cycle unit operating in combined cycle mode.

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

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

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

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

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

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

(f-2) A Market Seller's hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves, plus any redispatch costs incurred in accordance with section 10(a) of this Schedule, shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (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.

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 busses that define all interfaces or all hubs are located in the region. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by busses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed in accordance with the following provisions:

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of an Operating Reserve shortage in real-time or where PJM initiates the request for load reductions in real-time in order to avoid an Operating Reserve shortage.

(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 <= 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

$$Ramp_Request_t = (UDStarget_{t-1} - AOutput_{t-1}) \Big/ (UDSLAtime_{t-1})$$

$$RL_Desired_t = AOutput_{t-1} + \left(Ramp_Request_t * Case_Eff_time_{t-1} \right)$$

where:

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

To determine if a 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 <= 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 n 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 to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve charges shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve charges shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve charges shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region. For the purposes of this section, the Western Region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, *DEOK* transmission Zones, and the Eastern Region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones. The regional balancing Operating Reserve rates shall be determined in accordance with the following provisions:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

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

(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.

3.2.3A Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). An Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts if any, described in subsections (g), (h) and (i) of this section.

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

i) Credits for Synchronized Reserve provided by generation *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*; with the exception of those hours in which the Non-Synchronized Reserve Market Clearing Price for the applicable Reserve 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 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 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, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve requirement in a Reserve 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, but less than or equal to the sum of the Synchronized Reserve Penalty Factor and the Primary Reserve Penalty Factor for the Reserve Zone. If the Office of the Interconnection has initiated in a Reserve 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.

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

i. $250/MWh for the 2011/2012 Delivery Year;

ii. $400/MWh for the 2012/2013 Delivery Year;

iii. $550/MWh for the 2013/2014 Delivery Year; and

iv. $850/MWh as of the 2014/2015 Delivery Year.

After June 1, 2014, 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 the 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 expected Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set

point for the generation resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

(g) Charges for Tier 1 Synchronized Reserve will be allocated in proportion to the amount of Tier 1 Synchronized Reserve applied to each Synchronized Reserve Obligation. In the event Tier 1 Synchronized Reserve is provided by a Market Seller in excess of that Market Seller's Synchronized Reserve Obligation, the remainder of the Tier 1 Synchronized Reserve that is not utilized to fulfill the Seller's obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

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

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

(j) In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled by the owner to provide Tier 2 Synchronized Reserve fails to provide the assigned or self-scheduled amount of Synchronized Reserve in response to an actual Synchronized Reserve Event, , *the 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 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 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 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 for the hour ("Non-Synchronized Reserve Obligation"). 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 (d) of this section, plus the amounts if any, described in paragraphs (g), (h) and (i) 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 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. Opportunity costs for Demand Resources to provide Non-Synchronized Reserves are zero.*

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve 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 serving the next increment of demand for Non- Synchronized Reserve in each Reserve Zone inclusive of opportunity costs associated with meeting the Primary Reserve requirement. When the Primary Reserve requirement in a Reserve 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 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.

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

i. $250/MWh for the 2011/2012 Delivery Year;

ii. $400/MWh for the 2012/2013 Delivery Year;

iii. $550/MWh for the 2013/2014 Delivery Year; and

iv. $850/MWh as of the 2014/2015 Delivery Year.

After June 1, 2014, 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 solely for the purpose of providing Non-Synchronized Reserves shall be equal to the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Non-Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. The opportunity costs for a Demand Resource shall be zero.

(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 difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation

resource (at the megawatt level of the Synchronized Reserve set point for the generation resource) in the PJM Interchange Energy Market. The opportunity costs for a Demand Resource shall be zero.

(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 or a Demand Resource, except for Batch Load Demand Resources covered by Section 3.2.3A(1), 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.

(h) 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 Non-Synchronized Reserve fails to provide the assigned or self-scheduled 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.
(i) 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 megawattts in its offer at the start of a Non-Synchronized Reserve Event shall be the difference between (i) the Batch Load Demand Resource's consumption at the end of the Non-Synchronized Reserve Event and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the end of the Non-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 Non-Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.

3.2.3A.01 Day-ahead Scheduling Reserves.

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

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

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

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

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

(iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the

Interconnection, and a resource's ending MW usage shall be the lowest consumption between one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

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

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

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

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit hourly in an amount equal to {(LMPDMW - AG) x (URTLMP - UB)}

where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

AG equals the actual hourly integrated output of the unit;

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

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

where URTLMP - UB shall not be negative.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market

Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

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

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

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

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

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

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

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to Section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit hourly in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual hourly integrated output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

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

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

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generation unit's bus, (C) the generation unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation

unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

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

3.2.5 Transmission Loss Charges.

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

3.2.6 Emergency Energy.

(a) *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.

3.3 Market Sellers.

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

3.3.1 Spot Market Energy Charges.

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

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

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

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

3.3.2 Regulation.

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

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

3.3.3 Operating Reserves.

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

3.3.4 Emergency Energy.

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

3.3.5 Synchronized Reserve.

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

3.*3.5A Non-Synchronized Reserve.*

Each Market Seller that is also an Internal Market Buyer shall have an hourly Non-Synchronized Reserve objective and shall be credited or charged in connection therewith as specified in Section 3.2.3A.001(a). All other Market Sellers supplying Non-Synchronized Reserve at the direction of the Office of the Interconnection shall be credited for each increment of such Synchronized Reserve at the price specified in Section 3.2.3A.001(b), as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

3.3.6 Billing.

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

6A [Reserved For Future Use]

6A.1 [Reserved For Future Use]

6A.2 [Reserved For Future Use]

6A.3 [Reserved For Future Use]

Emergency Operations

PJM will initiate the request for load reduction following the declaration of Maximum Emergency Generation and prior to the implementation of Load Management Steps 1 and 2. (Implementation of the Emergency Load Response Program can be used for regional emergencies.) It is implemented whenever generation is needed that is greater than the highest economic incremental cost. PJM posts the request for load reduction on the PJM website, on the Emergency Conditions page, and on eData, and issues a burst email to the Emergency Load Response majordomo. A separate All-Call message is also issued.

Following PJM's request to reduce load, (i) participants in the Energy Only Option voluntarily may reduce load; and (ii) participants in the Full Program Option are required to reduce load unless they already have reduced load pursuant to the Economic Load Response Program. PJM will dispatch the resources of all Emergency Load Response Program participants (not already dispatched under the Economic Load Response Program) based on the Minimum Dispatch Prices specified in the participants' Emergency Registration Forms.

The Minimum Dispatch Price *and all offers* of Full Program Option *resources and Energy Only Option resources in the Emergency Load Response Program are eligible to* set the real time Locational Marginal Prices ("LMP") *when the Office of the Interconnection has implemented Emergency procedures and such resources are required* to *reduce* demand in the PJM Region*, so long as sufficient data is available to accurately model the resources.* Energy Only Option resource*s must also* satisf*y* PJM's telemetry requirements.

Participants in the Emergency Load Response Program must provide real-time operational data regarding the availability and status of their resources to PJM, as described in detail in the PJM Manuals. Operational procedures are described in detail in the ***PJM Manual for Emergency Operations.***

Attachment A

Chart Containing the Tariff and Operating Agreement Revisions for the Market-Based Pricing Option and Administrative Cap Option

No.	PJM Section Title	Revisions for Shortage Pricing Option	Revisions for Administrative Cap Option
1.	OATT Definition "R-S"	***1.38D Reserve Zone.*** *"Reserve Zone" shall mean any of those geographic areas consisting of a combination of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, reserve service.* **1.42E Synchronized Reserve Zone:** *~~Any of those geographic areas consisting of a combination of one or more of the Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, Synchronized Reserve service.~~[Reserved]*	**N/A**
2.	OATT Schedule 3	**Regulation and Frequency Response Service** a. Regulation shall be supplied to meet the Regulation objective of a Regulation Zone from resources located within the metered electrical boundaries of such Regulation Zone. Resources offering Regulation shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the ~~procedures of the Office of the Interconnection~~PJM Manuals. b. The Office of the Interconnection shall obtain and maintain an amount of Regulation for each Regulation Zone equal to the Regulation objective for such Regulation Zone, as specified in ~~its procedures~~the PJM Manuals. c. The Regulation range of a resource shall be at least twice the amount of Regulation assigned~~.~~ as described in the ~~procedures of the Office of the Interconnection~~PJM Manuals. d. A resource capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced from the Regulation range by at least twice the amount of the Regulation provided with consideration of the Regulation limits of the resource, as specified in the PJM Manuals. ~~The amount of regulation provided by a unit shall serve to redefine the normal minimum generation and normal maximum generation energy limits~~	**Regulation and Frequency Response Service** a. Regulation shall be supplied to meet the Regulation objective of a Regulation Zone from resources located within the metered electrical boundaries of such Regulation Zone. Resources offering Regulation shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the ~~procedures of the Office of the Interconnection~~PJM Manuals. b. The Office of the Interconnection shall obtain and maintain an amount of Regulation for each Regulation Zone equal to the Regulation objective for such Regulation Zone, as specified in ~~its procedures~~the PJM Manuals. c. The Regulation range of a resource shall be at least twice the amount of Regulation assigned~~.~~ as described in the ~~procedures of the Office of the Interconnection~~PJM Manuals. d. A resource capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced from the Regulation range by at least twice the amount of the Regulation provided with consideration of the Regulation limits of the resource, as specified in the PJM Manuals. ~~The amount of regulation provided by a unit shall serve to redefine the normal minimum generation and normal maximum generation energy limits~~

No.	PJM Section Title	Revisions for Shortage Pricing Option	Revisions for Administrative Cap Option
		~~of that unit, in that the amount of regulation shall be added to the unit's normal minimum generation energy limit, and subtracted from its normal maximum generation energy limit.~~ e. Qualified Regulation must satisfy the measurement and verification tests described in the ~~procedures of the Office of the Interconnection~~PJM Manuals. h. The Office of the Interconnection shall dispatch resources for Regulation by sending Regulation signals and instructions to resources from which Regulation service has been offered, in accordance with the ~~procedures of the Office of the Interconnection~~PJM Manuals. Those resources shall comply with ~~r~~Regulation dispatch signals and instructions transmitted by the Office of the Interconnection and, in the event of conflict, ~~r~~Regulation dispatch signals and instructions shall take precedence over energy dispatch signals and instructions. Those providing ~~r~~Regulation shall exert all reasonable efforts to operate, or ensure the operation of, their resources supplying load in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.	~~of that unit, in that the amount of regulation shall be added to the unit's normal minimum generation energy limit, and subtracted from its normal maximum generation energy limit.~~ e. Qualified Regulation must satisfy the measurement and verification tests described in the ~~procedures of the Office of the Interconnection~~PJM Manuals. h. The Office of the Interconnection shall dispatch resources for Regulation by sending Regulation signals and instructions to resources from which Regulation service has been offered, in accordance with the ~~procedures of the Office of the Interconnection~~PJM Manuals. Those resources shall comply with ~~r~~Regulation dispatch signals and instructions transmitted by the Office of the Interconnection and, in the event of conflict, ~~r~~Regulation dispatch signals and instructions shall take precedence over energy dispatch signals and instructions. Those providing ~~r~~Regulation shall exert all reasonable efforts to operate, or ensure the operation of, their resources supplying load in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.
3.	OA Schedule 1 / OATT Att K Appendix - 1.3	***1.3.17B Non-Synchronized Reserve.*** *"Non-Synchronized Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.* ***1.3.17C Non-Synchronized Reserve Event.*** *"Non-Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources and/or Demand Resources able, assigned or self-scheduled, to provide Non-Synchronized Reserve within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-schedule Non-Synchronized Reserve capability.* ***1.3.29A Primary Reserve.*** *"Primary Reserve" shall mean the total reserve capability of*	**N/A**

No.	PJM Section Title	Revisions for Shortage Pricing Option	Revisions for Administrative Cap Option
		generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes of a request from the Office of the Interconnection dispatcher, and is comprised of both Synchronized Reserve and Non-Synchronized Reserve. ***1.3.31.001 Reserve Penalty Factor.*** *"Reserve Penalty Factor" shall mean the cost, in $/MWh, associated with being unable to meet a specific reserve requirement in a Reserve Zone. A Reserve Penalty Factor will be defined for each reserve requirement in a Reserve Zone.*	
4.	OA Schedule 1 / OATT Att K Appendix Section 1.7	**1.7.18 Regulation.** (a) Regulation to meet the Regulation objective of each Regulation Zone shall be supplied from generation resources and/or Demand Resources located within the metered electrical boundaries of such Regulation Zone. Generating Market Buyers, and Market Sellers offering Regulation, shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the PJM Manuals. (b) The Office of the Interconnection shall obtain and maintain an amount of Regulation for each Regulation Zone equal to the Regulation objective for such Regulation Zone, as specified in its PJM Manuals. (c) The Regulation range of a generation unit or Demand Resource shall be at least twice the amount of Regulation assigned as described in the PJM Manuals.~~.~~ (d) A resource capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced from the Regulation range by at least twice the amount of the Regulation provided with consideration of the ~~regulation~~Regulation limits of the resource, as specified in the ~~procedures of the Office of the Interconnection~~PJM Manuals. ~~A generation unit capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced by twice the amount of the~~	**1.7.18 Regulation.** (a) Regulation to meet the Regulation objective of each Regulation Zone shall be supplied from generation resources and/or Demand Resources located within the metered electrical boundaries of such Regulation Zone. Generating Market Buyers, and Market Sellers offering Regulation, shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the PJM Manuals. (b) The Office of the Interconnection shall obtain and maintain an amount of Regulation for each Regulation Zone equal to the Regulation objective for such Regulation Zone, as specified in its PJM Manuals. (c) The Regulation range of a generation unit or Demand Resource shall be at least twice the amount of Regulation assigned as described in the PJM Manuals.~~.~~ (d) A resource capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced from the Regulation range by at least twice the amount of the Regulation provided~~.~~ with consideration of ~~The~~ the ~~amount of~~ Regulation limits of the ~~provided by a~~ resource, as specified in the PJM Manuals ~~shall serve to redefine the normal minimum generation and normal maximum generation energy limits of that unit, in that the amount of Regulation shall be added to the unit's~~

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		~~Regulation provided. The amount of Regulation provided by a generation unit shall serve to redefine the Normal Minimum Generation and Normal Maximum Generation energy limits of that generation unit, in that the amount of Regulation shall be added to the generation unit's Normal Minimum Generation energy limit, and subtracted from its Normal Maximum Generation energy limit.~~ (e) Qualified Regulation must satisfy the measurement and verification tests described in the ~~procedures of the Office of the Interconnection~~PJM Manuals. ***1.7.19A Synchronized Reserve.*** (a) Synchronized Reserve shall be supplied from generation resources and/or Demand Resources located within the metered boundaries of the PJM Region. Generating Market Buyers, and Market Sellers offering Synchronized Reserve shall comply with applicable standards and requirements for Synchronized Reserve capability and dispatch specified in the PJM Manuals (b) The Office of the Interconnection shall obtain and maintain for each ~~*Synchronized*~~ Reserve Zone an amount of Primary and Synchronized Reserve equal to the *respective Primary and* Synchronized Reserve objectives for such ~~*Synchronized*~~ Reserve Zone, as specified in the PJM Manuals. ***1.7.19A.01 Non-Synchronized Reserve.*** *(a) Non-Synchronized Reserve shall be supplied from generation resources and/or Demand Resources located within the metered boundaries of the PJM Region. Generating Market Buyers and Market Sellers offering Non-Synchronized Reserve shall comply with applicable standards and requirements for Non-Synchronized Reserve capability and dispatch specified in the PJM Manuals.* *(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone an amount of Non-Synchronized Reserve such that the sum of the Synchronized Reserve and Non-Synchronized Reserve meets the Primary Reserve objective for such Reserve*	~~normal minimum generation energy limit, and subtracted from its normal maximum generation energy limit~~. (e) Qualified Regulation must satisfy the measurement and verification tests described in the ~~procedures of the Office of the Interconnection~~PJM Manuals.

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		Zone, as specified in the PJM Manuals. *(c) The Non-Synchronized Reserve capability of a generation resource and Demand Resource shall be the increase in energy output or load reduction achievable by the generation resource and Demand Resource within a continuous 10-minute period provided that the resource is not synchronized to the system at the initiation of the response.*	
5.	OA Schedule 1 / OATT Att K Appendix Section 1.10A	**1.10.1A Day-ahead Energy Market Scheduling** (d) Market Sellers wishing to sell into the Day-ahead Energy Market shall submit offers for the supply of energy (including energy from hydropower units), demand reductions, Regulation, Operating Reserves or other services for the following Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Attachment DD of the PJM Tariff, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. *Any offer not designated as a Maximum Emergency Offer shall be considered available for scheduling and dispatch under both Emergency and non-Emergency conditions. Offers may only be designated as Maximum Emergency Offers to the extent that the Generation Capacity Resource falls into at least one of the following categories:* *i) Environmental limits. If the resource has a limit on its run hours imposed by a federal, state or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited to operating only*	**N/A**

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		during declared PJM capacity emergencies by a governmental authority. *ii) Fuel limits. If physical events beyond the control of the resource owner result in the temporary interruption of fuel supply and there is limited on-site fuel storage. A fuel supplier's exercise of a contractual right to interrupt supply or delivery under an interruptible service agreement shall not qualify as an event beyond the control of the resource owner.* *iii) Temporary emergency conditions at the unit. If temporary emergency physical conditions at the resource significantly limit its availability.* *iv) Temporary megawatt additions. If a resource can provide additional megawatts on a temporary basis by oil topping, boiler over-pressure, or similar techniques and such megawatts are not ordinarily otherwise available.* The submission of offers for resource increments that have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, and the PJM Manuals, as applicable. Energy offered from generation resources that have not cleared a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region. The foregoing offers: i) Shall specify the Generation Capacity Resource or Demand Resource and energy or demand reduction, amount, respectively, for each hour in the offer period, and the minimum run time for generation resources and minimum down time for Demand Resources; ii) Shall specify the amounts and prices for the entire	

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		Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection; iii) If based on energy from a specific *generation~~g~~ resource~~unit~~*, may specify start-up and no-load fees equal to the specification of such fees for such ~~*unit*~~ *resource* on file with the Office of the Interconnection, if based on reductions in demand from a Demand Resource may specify shutdown costs; iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees; v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with a second schedule applicable if accepted after the foregoing deadline; vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer, which offer shall remain open through the Operating Day for which the offer is submitted; vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day; and viii) Shall not exceed an energy offer price of $1,000/megawatt-hour *for all generation resources and Demand Resources that have cleared a Base Residual Auction or an Incremental Auction*.	
6.		(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation that shall specify the megawatt of Regulation being offered, which must equal or exceed 0.1 megawatts, the Regulation Zone for which such Regulation is offered, the price of the capability offer in dollars per MW~~h~~, the price of the performance offer in Dollars per change in MW, and such other information specified by the Office of the	(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation that shall specify the megawatt of Regulation being offered, which must equal or exceed 0.1 megawatts, the Regulation Zone for which such ~~regulation~~Regulation is offered, the price of the capability offer in dollars per MW~~h~~, the price of the performance offer in Dollars per change in MW, and such other information specified by the Office

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		Interconnection as may be necessary to evaluate the offer and the resource's opportunity costs. The ~~price of the offer~~ total of the performance offer multiplied by the historical average mileage used in the market clearing plus the capability offer shall not exceed $100 per MWh in the case of Regulation offered for all Regulation Zones. In addition to any market-based offer for Regulation, the Market Seller also shall submit a cost-based offer. A cost-based offer must be in the form specified in the PJM Manuals and consist of the following components as well as any other components specified in the PJM Manuals: i. The costs (in $/MW) of the fuel cost increase due to the heat rate increase resulting from operating the unit at lower megawatt output incurred from the provision of Regulation; ii. The cost increase (in $/MW) in variable operating and maintenance costs resulting from operating the unit at lower megawatt output incurred from the provision of Regulation; and iii. An adder of up to $12.00 per megawatt of Regulation provided applied to the capability offer. Qualified Regulation capability must satisfy the measurement and verification tests specified in the PJM Manuals.	of the Interconnection as may be necessary to evaluate the offer and the resource's opportunity costs. The ~~price of the offer~~ total of the performance offer multiplied by the historical average mileage used in the market clearing plus the capability offer shall not exceed $100 per MWh in the case of Regulation offered for all Regulation Zones. In addition to any market-based offer for Regulation, the Market Seller also shall submit a cost-based offer. A cost-based offer must be in the form specified in the PJM Manuals and consist of the following components as well as any other components specified in the PJM Manuals: i. The costs (in $/MW) of the fuel cost increase due to the heat rate increase resulting from operating the unit at lower megawatt output incurred from the provision of Regulation; ii. The cost increase (in $/MW) in variable operating and maintenance costs resulting from operating the unit at lower megawatt output incurred from the provision of Regulation; and iii. An adder of up to $12.00 per megawatt of Regulation provided applied to the capability offer. Qualified Regulation capability must satisfy the measurement and verification tests specified in the PJM Manuals.
7.	OA Schedule 1 / OATT Att K Appendix Section 1.11	**1.11.4A Synchronized Reserve.** (b) The Office of the Interconnection shall obtain Synchronized Reserve from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Demand Resources as needed to meet the Synchronized Reserve requirements of each ~~*Synchronized*~~ Reserve Zone of the PJM Region not otherwise satisfied by the Market Buyers. Resources offering to sell Synchronized Reserve shall be selected to provide Synchronized Reserve on the basis of each generation resource's and/or Demand Resource's Synchronized Reserve offer and the estimated unit specific opportunity cost of the resource providing Synchronized Reserve, and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Synchronized Reserve and other ancillary	**N/A**

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		services. Estimated unit specific opportunity costs for generation resources shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the generation resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources will be zero. ***1.11.4B Non-Synchronized Reserve.*** *(a) A Market Buyer may satisfy its Non-Synchronized Reserve Obligation from its own generation resources and/or Demand Resources capable of providing Non-Synchronized Reserve, by contractual arrangements with other Market Participants able to provide Non-Synchronized Reserve, or by purchases from the PJM Non-Synchronized Reserve Market at the rates set forth in Section 3.2.3A.001.* *b) The Office of the Interconnection shall obtain Non-Synchronized Reserve from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Demand Resources as needed to ensure the Primary Reserve requirement of each Reserve Zone of the PJM Region not otherwise satisfied by the Market Buyers. Resources offering to sell Non-Synchronized Reserve shall be selected to provide Non-Synchronized Reserve on the basis of each generation resource's and/or Demand Resource's estimated unit specific opportunity cost of the resource providing Non-Synchronized Reserve, and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Synchronized Reserve and other ancillary services. Estimated unit specific opportunity costs for generation resources shall be equal to*	

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		the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the absolute value of the difference between the Locational marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Non-Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources will be zero. *(c) The Office of the Interconnection shall dispatch generation resources and/or Demand Resources for Non-Synchronized Reserve by sending Non-Synchronized Reserve instructions to generation resources and/or Demand Resources from which Non-Synchronized Reserve is available, in accordance with the PJM Manuals. Market Sellers shall comply with Non-Synchronized Reserve dispatch instructions transmitted by the Office of the Interconnection and, in the event of a conflict, Non-Synchronized Reserve dispatch instructions shall take precedence over energy dispatch signals and instructions. Market Sellers shall exert all reasonable efforts to operate, or ensure the operation of, their generation resources supplying load in the PJM Region as close to desired output levels as practical, consistent with Good Utility Practice.*	
8.	OA Schedule 1 / OATT Att K Appendix Section 2.2	**2.2 General.** The Office of the Interconnection shall determine the least cost security-constrained dispatch, which is the least costly means of serving load *and meeting reserve requirements* at different locations in the PJM Region based on actual operating conditions existing on the power grid (including transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6) and on the prices at which Market Sellers have offered to supply energy and offers by Economic Load Response Participants to reduce demand that qualify to set Locational Marginal Prices in the PJM Interchange Energy Market. Locational Marginal Prices for the generation and load busses in the PJM Region, including interconnections with other Control Areas, will be calculated based	**2.2 General.** The Office of the Interconnection shall determine the least cost security-constrained dispatch, which is the least costly means of serving load and meeting reserve requirements at different locations in the PJM Region based on actual operating conditions existing on the power grid (including transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6) and on the prices at which Market Sellers have offered to supply energy and offers by Economic Load Response Participants to reduce demand that qualify to set Locational Marginal Prices in the PJM Interchange Energy Market. Locational Marginal Prices for the generation and load busses in the PJM Region, including interconnections with other Control Areas, will be calculated based

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		on the actual economic dispatch and the prices of energy and demand reduction offers. The process for the determination of Locational Marginal Prices shall be as follows: (b) Using the prices at which energy is offered by Market Sellers and demand reductions are offered by Economic Load Response Participants to the PJM Interchange Energy Market, the Office of the Interconnection shall determine the offers of energy and demand reductions that will be considered in the calculation of Locational Marginal Prices. As described in Section 2.4 below, every qualified offer for demand reduction and of energy by a Market Seller from resources that are ~~*following economic dispatch instructions of*~~ *dispatched by* the Office of the Interconnection will be utilized in the calculation of Locational Marginal Prices. Offers of *economic load response*~~*demand reduction*~~ from Demand Resources in the Real-time Energy Market will not be eligible to set Locational Marginal Prices, unless metered directly by the Office of the Interconnection. *Offers of Full Program Option resources in the Emergency Load Response Program are eligible to set real time Locational Marginal Prices when the Office of the Interconnection has implemented Emergency procedures and such resources are required to reduce demand in the PJM Region, so long as sufficient data is available to accurately model the resources.*	on the actual economic dispatch and the prices of energy and demand reduction offers. The process for the determination of Locational Marginal Prices shall be as follows:
9.	OA Schedule 1 / OATT Att K Appendix Section 2.3	**2.3 Determination of System Conditions Using the State Estimator.** Power system operations, including, but not limited to, the determination of the least costly means of serving load *and meeting reserve requirements*, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In calculating Locational Marginal Prices, the Office of the Interconnection shall obtain a complete and consistent description of conditions on the electric network in the PJM Region by using the most recent power flow solution produced by the State Estimator *program and utilized in the PJM dispatch algorithm*, which *State Estimator program* is also used by the Office of the Interconnection for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available real-time metering information, information regarding the current	**2.3 Determination of System Conditions Using the State Estimator.** Power system operations, including, but not limited to, the determination of the least costly means of serving load and meeting reserve requirements, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In calculating Locational Marginal Prices, the Office of the Interconnection shall obtain a complete and consistent description of conditions on the electric network in the PJM Region by using the most recent power flow solution produced by the State Estimator program and utilized in the PJM dispatch algorithm, which State Estimator program is also used by the Office of the Interconnection for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available real-time metering information, information regarding the current

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		status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at buses for which real-time information is unavailable. The Office of the Interconnection shall obtain a State Estimator solution every five minutes, which shall provide the megawatt output of generators and the loads at buses in the PJM Region, transmission line losses, and actual flows or loadings on constrained transmission facilities. External transactions between PJM and other Control Areas shall be included in the Locational Marginal Price calculation on the basis of the real time transaction schedules implemented by the Office of the Interconnection's dispatcher.	status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at buses for which real-time information is unavailable. The Office of the Interconnection shall obtain a State Estimator solution every five minutes, which shall provide the megawatt output of generators and the loads at buses in the PJM Region, transmission line losses, and actual flows or loadings on constrained transmission facilities. External transactions between PJM and other Control Areas shall be included in the Locational Marginal Price calculation on the basis of the real time transaction schedules implemented by the Office of the Interconnection's dispatcher.
10.	OA Schedule 1 / OATT Att K Appendix Section 2.4	**2.4 Determination of Energy Offers Used in Calculating Real-time Prices.** (a) During the Operating Day, real-time Locational Marginal Prices derived in accordance with this Section shall be determined every five minutes and integrated hourly values of such determinations shall be the basis of sales and purchases of energy in the Real-time Energy Market and of Transmission Congestion Charges under the PJM Tariff not covered by the Day-ahead Energy Market. (b) To determine the energy offers submitted to the PJM Interchange Energy Market that shall be used during the Operating Day to calculate the Real-time Prices, the Office of the Interconnection shall determine *the applicable marginal energy offer of the* ~~*which*~~ resources ~~*are following its economic dispatch instructions*~~*being dispatched by the Office of the Interconnection*. A resource ~~*will be considered to be following economic dispatch instructions and*~~ shall be included in the calculation of Real-time Prices if~~*: i)*~~ the applicable ~~*price bid by a Market Seller for energy from the*~~ *marginal energy offer of the* resource *being dispatched by the Office of the Interconnection* is less than or equal to the Dispatch Rate for the area of the PJM Region in which the resource is located*.*~~*; or*~~ ~~*ii) the resource is specifically requested to operate by the Office of the Interconnection's dispatcher.*~~ (c) In determining whether a resource satisfies the condition	**N/A**

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		described in (b), the Office of the Interconnection will determine the ~~bid price associated with an~~ applicable marginal energy offer by comparing the ~~actual~~ requested megawatt output of the resource with the Market Seller's offer price curve. ~~Because of practical generator response limitations, a resource whose megawatt output is not ten percent more than the megawatt level specified on the offer price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but t~~The applicable marginal energy ~~price~~ offer used in the calculation of Real-time Prices shall not exceed the applicable Dispatch Rate. Units that must be run for local area protection shall not be considered in the calculation of Real-time Prices.	
11.	OA Schedule 1 / OATT Att K Appendix Section 2.5	**2.5 Calculation of Real-time Prices.** (a) The Office of the Interconnection shall determine the least costly means of obtaining energy to serve the next increment of load at each bus in the PJM Region represented in the State Estimator and each Interface Pricing Point between PJM and an adjacent Control Area, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and utilized in the PJM dispatch algorithm and the energy offers that are the basis for the Day-ahead Energy Market, or that are determined to be eligible for consideration under Section 2.4 in connection with the real-time dispatch, as applicable. This calculation shall be made by applying ~~an incremental linear optimization method to minimize energy costs~~ a real-time joint optimization of energy and reserves, given actual system conditions, a set of energy offers, a set of reserve offers, a set of Reserve Penalty Factors, and any binding transmission constraints that may exist. In performing this calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a generation resource or decrease an increment of energy being consumed by a Demand Resource, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the	**2.5 Calculation of Real-time Prices.** (a) The Office of the Interconnection shall determine the least costly means of obtaining energy to serve the next increment of load at each bus in the PJM Region represented in the State Estimator and each Interface Pricing Point between PJM and an adjacent Control Area, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and utilized in the PJM dispatch algorithm and the energy offers that are the basis for the Day-ahead Energy Market, or that are determined to be eligible for consideration under Section 2.4 in connection with the real-time dispatch, as applicable. This calculation shall be made by applying ~~an incremental linear optimization method to minimize energy costs~~ a real-time joint optimization of energy and reserves, given actual system conditions, a set of energy offers, a set of reserve offers, and any binding transmission constraints that may exist. In performing this calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a generation resource or decrease an increment of energy being consumed by a Demand Resource, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the

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		output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses. ~~*The energy offer or offers that can serve an increment of load at a bus at the lowest cost, calculated in this manner, shall determine the Real-time Price at that bus.*~~ *The real-time Locational Marginal Prices at a bus shall be determined through the joint optimization based on the lowest marginal cost to serve the next increment of load at the bus taking into account the applicable reserve requirements, unit resource constraints, transmission constraints and marginal loss impact.* *(b) If all reserve requirements in every modeled Reserve Zone can be met at prices less than or equal to the Reserve Penalty Factors for both the Synchronized Reserves and Non-synchronized Reserves, real-time Locational Marginal Prices shall be calculated as described in Section 2.5(a) above and no Reserve Penalty Factor shall apply beyond the normal lost opportunity costs incurred by the reserve requirements. When a reserve requirement cannot be met at a price less than or equal to the Reserve Penalty Factors associated with a Reserve Zone, the real-time Locational Marginal Prices shall be calculated by incorporating the applicable Reserve Penalty Factor for the deficient reserve product as the lost opportunity cost impact of the deficient reserve requirement, and the components of Locational Marginal Prices referenced in Section 2.5(a) above shall be calculated accordingly.* *(c) If the Office of the Interconnection has initiated in a Reserve Zone either a voltage reduction action as described in the PJM Manuals or a manual load dump action as described in the PJM Manuals, Locational Marginal Prices for that Reserve Zone will be calculated including the Reserve Penalty Factors of all reserve products in that Reserve Zone.*	consumption by a Demand Resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses. ~~The energy offer or offers that can serve an increment of load at a bus at the lowest cost, calculated in this manner, shall determine the Real-time Price at that bus.~~ The real-time Locational Marginal Prices at a bus shall be determined through the joint optimization based on the lowest marginal cost to serve the next increment of load at the bus taking into account the applicable reserve requirements, unit resource constraints, transmission constraints and marginal loss impact. (b) If PJM is able to meet its Synchronized Reserve requirements as specified in 1.7.19A, real-time Locational Marginal Prices shall be calculated as described in Section 2.5(a) above. When Synchronized Reserve requirements cannot be met, the real-time Locational Marginal Prices shall be calculated in accordance with 2.5(a) above and Section 6A of this Schedule 1. (~~b~~c) During the Operating Day, the calculation set forth in (a) shall be performed every five minutes, using the Office of the Interconnection's Locational Marginal Price program, producing a set of Real-time Prices based on system conditions during the preceding interval. The prices produced at five-minute intervals during an hour will be integrated to determine the Real-time Prices for that hour.

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		(~~b~~d) During the Operating Day, the calculation set forth in (a) shall be performed every five minutes, using the Office of the Interconnection's Locational Marginal Price program, producing a set of Real-time Prices based on system conditions during the preceding interval. The prices produced at five-minute intervals during an hour will be integrated to determine the Real-time Prices for that hour.	
12.	OA Schedule 1 / OATT Att K Appendix 1 Section 3.2.2	**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 ~~at~~: (i) the capability Regulation market-clearing price determined in accordance with subsection ~~(c)~~(g) of this section~~,~~; (ii) ~~plus~~ the amounts, if any, described in subsection (f) of this section; and (iii) the Internal Market Buyer's pro rata share of any performance credits paid to regulating resources calculated in accordance with subsection (g) of this section.	**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 ~~at~~: (i) the capability Regulation market-clearing price determined in accordance with subsection ~~(c)~~(g) of this section~~,~~; (ii) ~~plus~~ the amounts, if any, described in subsection (f) of this section; and (iii) the Internal Market Buyer's pro rata share of any performance credits paid to regulating resources calculated in accordance with subsection (g) of this section.
		(b) ~~A~~ 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 ~~in excess of its hourly Regulation obligation shall be credited~~ such that the calculated credit for each increment of ~~such~~ Regulation provided by each resource shall be ~~at the higher of (i)~~ the Regulation market-clearing price~~, in such Regulation Zone or (ii) the sum of the regulation offer and the unit-specific opportunity cost of the generation resource supplying the increment of Regulation, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.~~	(b) ~~A~~ 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 ~~in excess of its hourly Regulation obligation shall be credited~~ such that the calculated credit for each increment of ~~such~~ Regulation provided by each resource shall be ~~at the higher of (i)~~ the Regulation market-clearing price~~, in such Regulation Zone or (ii) the sum of the regulation offer and the unit-specific opportunity cost of the generation resource supplying the increment of Regulation, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.~~

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		(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 (f) 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 ~~highest sum of a resource's Regulation offer plus its *estimated*~~ unit-specific opportunity costs, *during the 5-minute period* determined as described in subsection (d) below from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.3.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.	(c) If PJM is able to meet its Synchronized Reserve requirements as specified in 1.7.19A, ~~The~~ 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 (f) 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 ~~highest sum of a resource's Regulation offer plus its estimated~~ unit-specific opportunity costs, during the 5-minute period determined as described in subsection (d) below from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.3.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.
		(d) In determining the Regulation *5-minute* ~~*market*~~ clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour shall be equal to ~~*the sum of the unit-specific opportunity costs (i) incurred during the hour in which the obligation is fulfilled, plus costs (ii) associated with uneconomic operation during the hour preceding the initial regulating hour ("preceding shoulder hour"), plus costs (iii) associated with uneconomic operation during the hour after the final regulating hour ("following shoulder hour").*~~ ~~*The unit-specific opportunity costs incurred during the hour in which the Regulation obligation is fulfilled shall be equal to*~~ the product of (i) the deviation of the set point of the generation	(d) In determining the Regulation 5-minute ~~market~~ clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour shall be equal to ~~the sum of the unit-specific opportunity costs (i) incurred during the hour in which the obligation is fulfilled, plus costs (ii) associated with uneconomic operation during the hour preceding the initial regulating hour ("preceding shoulder hour"), plus costs (iii) associated with uneconomic operation during the hour after the final regulating hour ("following shoulder hour").~~ ~~The unit-specific opportunity costs incurred during the hour in which the Regulation obligation is fulfilled shall be equal to~~ the product of (i) the deviation of the set point of the generation

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		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.	resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.
		~~*The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.*~~	~~The unit-specific opportunity costs associated with uneconomic operation during the 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*~~	~~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~~

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

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		~~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~~	~~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~~

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		~~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.~~	~~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~~e) 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.	(~~f~~e) 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.
		(f) 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 expected amount of Regulation that resource will be dispatched based on the historical ratio of control signals calculated by the Office of the Interconnection, and the ratio of benefits to system control for following the Regulation control signal 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 based on the assigned MW(s), the performance Regulation market-clearing price, the amount of Regulation performance of the resource provides during the market hour, and the accuracy with which each resource responds to the Office of the Interconnection's Regulation signals during the market hour.	(f) 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 expected amount of Regulation that resource will be dispatched based on the historical ratio of control signals calculated by the Office of the Interconnection, and the ratio of benefits to system control for following the Regulation control signal 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 based on the assigned MW(s), the performance Regulation market-clearing price, the amount of Regulation performance of the resource provides during the market hour, and the accuracy with which each resource responds to the Office of the Interconnection's Regulation signals during the market hour.
13.		(g) 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 (f) from the total Regulation market clearing price described in subsection (c). This residual sets the capability Regulation market clearing price for that market hour.	(g) 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 (f) from the total Regulation market clearing price described in subsection (c). This residual sets the capability Regulation market clearing price for that market hour.

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		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 capacity 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 capability based on the assigned MW and the capacity Regulation market-clearing price.
14.		(h) 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.	(hi) 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.
15.		**N/A**	(i) If PJM is unable to meet its Synchronized Reserve requirements as specified in 1.7.19A, the performance Regulation clearing price and the capability Regulation clearing price will be held steady for the duration of the reserve deficiency at the last value calculated prior to the start of the reserve deficiency. In the event of such reserve deficiency, 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 at the higher of (i) the Regulation market-clearing price in such Regulation Zone or (ii) the sum of the regulation offer and the unit-specific opportunity cost of the generation resource supplying the increment of Regulation.
16.	OA Schedule 1 / OATT Att K Appendix Section 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	**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

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		pursuant to this section, the following applies: (i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region for which the 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.	pursuant to this section, the following applies: (i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region for which the 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.
17.	OA Schedule 1 / OATT Att K Appendix Section 3.2.3	**3.2.3 Operating Reserves.** (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	**N/A**

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		operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day. Credits received pursuant to this section shall be equal to the positive difference between a resource's total offered price for start-up (shutdown costs for Demand Resources) and no-load fees and energy, determined on the basis of the resource's scheduled output, and the total value of the resource's energy as determined by the Real-time Energy Market and the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for segment 2 shall exclude start up (shutdown costs for Demand Resources) costs for generation resources. Except as provided in Section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to Section 3.2.3(b) plus the resource's opportunity cost and less any amounts credited for 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. Regulation, 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 Regulation, 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 period the unit operates in condensing and generation mode for one or more contiguous hours. (h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (i) load deviations (net of operating Behind The Meter	

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		Generation) from the Day-ahead Energy Market in megawatt-hours during that Operating Day; (ii) generation deviations (not including deviations in Behind The Meter Generation) from the Day-ahead Energy Market for non-dispatchable generation resources, including External Resources, in megawatt-hours during the Operating Day; (iii) deviations from the Day-ahead Energy Market for bilateral transactions from outside the PJM Region for delivery within such region in megawatt-hours during the Operating Day, except as noted below and in the PJM Manuals; and (iv) deviations of energy sales from the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such region pursuant to Section 1.12. Deviations that occur within a single Zone shall be associated with the Eastern or Western Region, as defined in Section 3.2.3(q) of this Schedule, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with Section 3.2.3(q). Deviations at interfaces and hubs shall be associated with the Eastern or Western Region if all the busses that define all interfaces or all hubs are located in the region. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by busses that are wholly contained within the same Zone. The foregoing notwithstanding, netting deviations shall be allowed in accordance with the following provisions: (i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus. (ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of an Operating	

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		Reserve shortage in real-time or where PJM initiates the request for load reductions in real-time in order to avoid an Operating Reserve shortage ~~*as described in this Schedule, Section 6A, Scarcity Pricing*~~.	
18.	OA Schedule 1 / OATT Att K Appendix Section 3.2.3A	**3.2.3A Synchronized Reserve.** (a) Each Internal Market Buyer that is a Load Serving Entity shall have an obligation for hourly Synchronized Reserve equal to its *pro rata* share of Synchronized Reserve requirements for the hour for each ~~*Synchronized*~~ Reserve Zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such ~~*Synchronized*~~ Reserve Zone, for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). An Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts if any, described in subsections (g), (h) and (i) of this section. (b) A Generating Market Buyer supplying Synchronized Reserve at the direction of the Office of the Interconnection, in excess of its hourly Synchronized Reserve Obligation, shall be credited as follows: i) Credits for Synchronized Reserve provided by generation ~~units~~ 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*; with the exception of those hours in which the Non-Synchronized Reserve Market Clearing Price for the applicable Reserve Zone is not equal to zero. During such hours, Tier 1 Synchronized Reserve resources shall be compensated at the Synchronized Reserve*	**3.2.3A Synchronized Reserve.** (e) In determining the 5-minute Synchronized Reserve ~~Market C~~clearing ~~P~~price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the expected Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. The opportunity costs for a Demand Resource shall be zero. (m) If PJM is unable to meet its Synchronized Reserve requirements as specified in 1.7.19A, the Synchronized Reserve Market Clearing Price will be held steady for the duration of the reserve deficiency at the last value calculated prior to the start of the reserve deficiency.

No.	PJM Section Title	Revisions for Shortage Pricing Option	Revisions for Administrative Cap Option
		Market Clearing Price for the applicable Reserve 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. (d) The Synchronized Reserve Market Clearing Price shall be determined for each ~~*Synchronized*~~ Reserve Zone by the Office of the Interconnection ~~*prior to the operating hour and such market-clearing price shall be equal to, from among the generation resources or Demand Resources selected to provide Synchronized Reserve for such Synchronized Reserve Zone, the highest sum of either (i) a generation resource's Synchronized Reserve offer and opportunity cost or (ii) a demand response resource's Synchronized Reserve offer.*~~ *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, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve requirement in a Reserve 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, but less than or equal to the sum of the Synchronized Reserve Penalty Factor and the Primary Reserve Penalty Factor for the Reserve Zone. If the Office of the Interconnection has initiated in a Reserve 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.* *The Synchronized Reserve Penalty Factors shall each be phased in as described below:* *i. $250/MWh for the 2011/2012 Delivery Year;* *ii. $400/MWh for the 2012/2013 Delivery Year;* *iii. $550/MWh for the 2013/2014 Delivery Year; and*	

No.	PJM Section Title	Revisions for Shortage Pricing Option	Revisions for Administrative Cap Option
		iv. $850/MWh as of the 2014/2015 Delivery Year. *After June 1, 2014, 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 the Delivery Year(s).* (e) In determining the *5-minute* Synchronized Reserve ~~*Market Cc*~~*l*earing ~~*P*~~*p*rice, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the expected Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. The opportunity costs for a Demand Resource shall be zero. (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	

No.	PJM Section Title	Revisions for Shortage Pricing Option	Revisions for Administrative Cap Option
		three business days following the Synchronized Reserve Event. The overall Synchronized Reserve requirement for each ~~Synchronized~~ Reserve Zone of the PJM Region on which the Synchronized Reserve Obligations, except for the additional obligations set forth in this section, are based shall be reduced by the amount of this shortfall for the applicable three-day period. ***3.2.3A.001 Non-Synchronized Reserve.*** *(a) Each Internal Market Buyer that is a Load Serving Entity 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 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 for the hour ("Non-Synchronized Reserve Obligation"). 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 (d) of this section, plus the amounts if any, described in paragraphs (g), (h) and (i) 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 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. Opportunity costs for Demand Resources to provide Non-Synchronized Reserves are zero.* *(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve 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*	

No.	PJM Section Title	Revisions for Shortage Pricing Option	Revisions for Administrative Cap Option
		the marginal cost of serving the next increment of demand for Non-Synchronized Reserve in each Reserve Zone inclusive of opportunity costs associated with meeting the Primary Reserve requirement. When the Primary Reserve requirement in a Reserve 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 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. *The Primary Reserve Penalty Factors shall each be phased in as described below:* *i. $250/MWh for the 2011/2012 Delivery Year;* *ii. $400/MWh for the 2012/2013 Delivery Year;* *iii. $550/MWh for the 2013/2014 Delivery Year; and* *iv. $850/MWh as of the 2014/2015 Delivery Year.* *After June 1, 2014, 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 solely for the purpose of providing Non-Synchronized Reserves shall be equal to the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Non-Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set*	

No.	PJM Section Title	Revisions for Shortage Pricing Option	Revisions for Administrative Cap Option
		point for the resource) in the PJM Interchange Energy Market. The opportunity costs for a Demand Resource shall be zero. (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 absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the generation resource) in the PJM Interchange Energy Market. The opportunity costs for a Demand Resource shall be zero. (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 or a Demand Resource, except for Batch Load Demand Resources covered by Section 3.2.3A(1), 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	

No.	PJM Section Title	Revisions for Shortage Pricing Option	Revisions for Administrative Cap Option
		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. *(h) 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 Non-Synchronized Reserve fails to provide the assigned or self-scheduled 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.* *(i) 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 megawattts in its offer at the start of a Non-Synchronized Reserve Event shall be the difference between (i) the Batch Load Demand Resource's consumption at the end of the Non-Synchronized Reserve Event and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the end of the Non-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 Non-Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.*	

No.	PJM Section Title	Revisions for Shortage Pricing Option	Revisions for Administrative Cap Option
19.	OA Schedule 1 / OATT Att K Appendix Section 3.2.6	**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. (~~b~~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. (~~c~~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.	**N/A**

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20.	OA Schedule 1 / OATT Att K Appendix Section 3.3	***3.3.5A Non-Synchronized Reserve.*** *Each Market Seller that is also an Internal Market Buyer shall have an hourly Non-Synchronized Reserve objective and shall be credited or charged in connection therewith as specified in Section 3.2.3A.001(a). All other Market Sellers supplying Non-Synchronized Reserve at the direction of the Office of the Interconnection shall be credited for each increment of such Synchronized Reserve at the price specified in Section 3.2.3A.001(b), as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.*	**N/A**
21.	OA Schedule 1 / OATT Att K Appendix Section 6A	***[Reserved For Future Use]*** ~~***6A Scarcity Pricing.***~~ ~~***6A.1 Scarcity Conditions.***~~ ~~***6A.1.1 Commencement of Scarcity Conditions.***~~ ~~*Scarcity conditions that trigger scarcity pricing will occur when the Office of the Interconnection's system operators perform any one of the following identifiable, specifically defined actions for a Scarcity Pricing Region:*~~ ~~*a) Begin to dispatch online generators, which are partially designated as Maximum Emergency, into emergency output levels.*~~ ~~*b) Begin to dispatch online generators, which are designated entirely as Maximum Emergency, above their designated minimum load points, if they are currently online and operating at their minimum load points because of restrictive operating parameters associated with the generators.*~~ ~~*c) Begin to dispatch any offline generators that are designated entirely as Maximum Emergency and that have start times plus notification times less than or equal to 30 minutes.*~~ ~~*d) Voltage reduction action as described in the PJM Manuals.*~~ ~~*e) Emergency energy purchases pursuant to section 1.6.2(vi) of this Schedule.*~~ ~~*f) Manual load dump action as described in the PJM Manuals.*~~ ~~*Whenever the Office of the Interconnection's system operators take any of the above designated actions triggering scarcity pricing, they shall post on the PJM website the emergency message describing*~~	**N/A**

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		~~the action and include in the posting the Scarcity Pricing Region for which the action is being taken.~~ ~~***[Reserved For Future Use]***~~ ~~***6A.1.2 Termination of Scarcity Conditions.***~~ ~~*Scarcity pricing will be terminated in a Scarcity Pricing Region when demand and reserves can be fully satisfied with generation that is not designated Maximum Emergency. Under this condition, some generation that is designated Maximum Emergency may continue to operate due to timing limitations or operating limitations, but that generation is no longer needed under dispatch to satisfy system requirements, and scarcity pricing will no longer apply. Under no circumstances shall scarcity conditions be terminated if any of the following conditions remain in effect for the Scarcity Pricing Region:*~~ ~~*a) Voltage reduction action as described in the PJM Manuals.*~~ ~~*b) Emergency energy purchases from offers that do not have minimum purchase requirements of greater than 30 minutes duration attached to the offer.*~~ ~~*c) Manual load dump action as described in the PJM Manuals.*~~ ~~*The Office of the Interconnection shall post on the PJM website the time when scarcity conditions are terminated.*~~ ~~***6A.1.3 Maximum Emergency Offer Limitations.***~~ ~~*For purposes of defining scarcity conditions, the Office of the Interconnection shall consider units that have been classified as Maximum Emergency only if they fall in one of the following categories:*~~ ~~*a) Environmental limits. If the unit has a hard cap on its run hours imposed by an environmental regulator that will temporarily significantly limit its availability.*~~ ~~*b). Fuel limits. If physical events beyond the control of the unit owner result in the temporary interruption of fuel supply and there is limited on-site fuel storage. A fuel supplier's exercise of a contractual right to interrupt supply or delivery under an interruptible service agreement shall not qualify as an event beyond the control of the unit owner.*~~ ~~*c) Temporary emergency conditions at the unit. If*~~	

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		~~*temporary emergency physical conditions at the unit significantly limit its availability.*~~ ***[Reserved For Future Use]*** ~~*d) Temporary megawatt additions. If a unit can provide additional megawatts on a temporary basis by oil topping, boiler over-pressure, or similar techniques and such megawatts are not ordinarily otherwise available.*~~ ~~*The Office of the Interconnection shall post on its website the aggregate amount of generation megawatts that are classified as Maximum Emergency.*~~ ~~***6A.2 Scarcity Pricing Regions.***~~ ~~***6A.2.1 Established Scarcity Pricing Regions.***~~ ~~*There shall be the following Scarcity Pricing Regions: (1) Entire Market Region consisting of all transmission zones in the PJM market; (2) Bedington-Black Oak Region consisting of all pricing nodes that have a 5% or greater positive power distribution factor ("dfax") relative to the Bedington-Black Oak constraint; (3) the Eastern MAAC Region consisting of all pricing nodes that have a 5% or greater dfax relative to the Eastern Reactive Transfer constraint, (4) Eastern Market Region consisting of all pricing nodes that have a 5% or greater positive dfax relative to the Bedington-Black Oak and the Central Reactive Transfer constraints; (5) the MAAC Region, consisting of all pricing nodes that have a 5% or greater positive dfax relative to the Western Reactive Transfer constraint; and (6) the AP South Region, consisting of all pricing nodes that have a 5% or greater positive dfax relative to the AP South Reactive Transfer constraint.*~~ ~~***6A.2.2 Annual Review of Scarcity Pricing Regions.***~~ ~~*On an annual basis, PJM will review the defined Scarcity Pricing Regions and file changes (additions or deletions) to them with the Commission, as required. Additional Scarcity Pricing Regions must meet the following criteria: (1) consist of at least two entire transmission zones; (2) consist of contiguous transmission zones and sub-zones; (3) transmission import or transfer must be limited by EHV (500 kV or greater) constraints; and (4) consist of pricing nodes that have a 5% or greater positive dfax relative to the*~~	

No.	PJM Section Title	Revisions for Shortage Pricing Option	Revisions for Administrative Cap Option
		~~constraints.~~ ***[Reserved For Future Use]*** ~~***6A.2.3 Additional Temporary Scarcity Pricing Regions.***~~ ~~*Additional temporary Scarcity Pricing Regions shall be designated by the Office of the Interconnection during the year when warranted by a non-transitory change in the topology of the transmission system. Additional temporary Scarcity Pricing Regions must meet the criteria set forth in section 6A.2.2. The Office of the Interconnection shall designate and post on the PJM website an additional temporary Scarcity Pricing Region within 72 hours of operational conditions warranting the additional temporary Scarcity Pricing Region. The temporary Scarcity Pricing Region shall become effective on the day following such posting, provided that the posting is before noon. If and when the topology is restored to its prior state or the change otherwise no longer warrants the designation of a temporary Scarcity Pricing Region, the Office of the Interconnection shall make a posting ending the additional designation. The termination of the temporary Scarcity Pricing Region shall become effective on the day following the posting, provided that the posting is before noon.*~~ ~~***6A.3 Scarcity Pricing.***~~ ~~*When scarcity conditions exist in a Scarcity Pricing Region, the region is considered incapable of meeting demand under normal economic dispatch conditions. Under such scarcity conditions, the Locational Marginal Prices of all nodes in a Scarcity Pricing Region will be determined based on the highest market-based offer price of all generating units operating under the Office of the Interconnection's direction to supply either energy or reserves on a real-time dispatch basis. No offer capping under section 6.4 of this Schedule may be initiated or continued in the Scarcity Pricing Region while scarcity pricing is in effect; provided, however, that generation in the Scarcity Pricing Region shall remain subject to the overall offer cap of $1000 per megawatt-hour. During the period that scarcity pricing is in effect, the Office of the Interconnection's system operators may direct generating units in the Scarcity Pricing Region to reduce from their maximum output*~~	

No.	PJM Section Title	Revisions for Shortage Pricing Option	Revisions for Administrative Cap Option
		~~for system or local transmission control. In such event, such reductions shall be treated as reductions for reliability under which the generation supplier shall be entitled to opportunity cost compensation equal to the megawatt-hour reduction times the difference between the Locational Marginal Price at the generator bus and the generation supplier's offer price consistent with section 3.2.3(f) of this Schedule. In addition, if a generator outside of a Scarcity Pricing Region is called upon to relieve the transmission constraint that caused the scarcity pricing condition in a Scarcity Pricing Region, then during the time that scarcity pricing is in effect in that Scarcity Pricing Region, that generation supplier shall be paid the higher of the generation-weighted Locational Marginal Price within the region determined as explained above or the price it otherwise would have been paid under this Schedule; however, that generation supplier's offer shall not be used to set Locational Marginal Prices in the Scarcity Pricing Region.~~	
22.	OA Schedule 1 / OATT Att K Appendix Emergency Operations	***Emergency Operations*** PJM will initiate the request for load reduction following the declaration of Maximum Emergency Generation and prior to the implementation of Load Management Steps 1 and 2. (Implementation of the Emergency Load Response Program can be used for regional emergencies.) It is implemented whenever generation is needed that is greater than the highest economic incremental cost. PJM posts the request for load reduction on the PJM web site, on the Emergency Conditions page, and on eData, and issues a burst email to the Emergency Load Response majordomo. A separate All-Call message is also issued. Following PJM's request to reduce load, (i) participants in the Energy Only Option voluntarily may reduce load; and (ii) participants in the Full Program Option are required to reduce load unless they already have reduced load pursuant to the Economic Load Response Program. PJM will dispatch the resources of all Emergency Load Response Program participants (not already dispatched under the Economic Load Response Program) based on the Minimum Dispatch Prices specified in the participants' Emergency Registration Forms.	**N/A**

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		The Minimum Dispatch Price *and all offers* of ~~a~~ Full Program Option ~~*participant*~~ *resources and Energy Only Option resources in the Emergency Load Response Program are eligible to* ~~*that reduces load may*~~ set the real time Locational ~~m~~Marginal Price*s* ("LMP") *when the Office of the Interconnection has implemented Emergency procedures and* ~~*provided that the*~~ *such resources* ~~*participant's load reductions*~~ *are* ~~*needed*~~ *required* to ~~*meet*~~ *reduce* demand in the PJM Region*, so long as sufficient data is available to accurately model the resources*. ~~*The Minimum Dispatch Price of an Energy Only Option participant that reduces load may set the real time LMP provided that such participant's load reductions are needed to meet demand in the PJM Regions and the*~~ Energy Only Option ~~*participant's*~~ resource*s must also* satisf*y*~~*ies*~~ PJM's telemetry requirements. Participants in the Emergency Load Response Program must provide real-time operational data regarding the availability and status of their resources to PJM, as described in detail in the PJM Manuals. Operational procedures are described in detail in the PJM Manual for Emergency Operations.	

Attachment B

Redline and Clean PDF Versions of the Tariff and Operating Agreement Sections Revisions Needed for the Administrative Cap Option

SCHEDULE 3
Regulation and Frequency Response Service

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

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

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

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

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

d. A resource capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced from the Regulation range by at least twice the amount of the Regulation provided~~.~~ with consideration of ~~The~~ the ~~amount of~~ Regulation limits of the ~~provided by a~~ resource, as specified in the PJM Manuals ~~shall serve to redefine the normal~~

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

e. Qualified Regulation must satisfy the measurement and verification tests described in the ~~procedures of the Office of the Interconnection~~PJM Manuals.

f. A Transmission Owner, Network Customer or other Transmission Customer may satisfy its Regulation obligation from its own resources capable of performing Regulation service, by contractual arrangements with others able to provide Regulation service on a comparable basis, or by purchases from the PJM Regulation market.

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

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

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

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

1.7 General.

1.7.1 Market Sellers.

Only Market Sellers shall be eligible to submit offers to the Office of the Interconnection for the sale of electric energy or related services in the PJM Interchange Energy Market. Market Sellers shall comply with the prices, terms, and operating characteristics of all Offer Data submitted to and accepted by the PJM Interchange Energy Market.

1.7.2 Market Buyers.

Only Market Buyers shall be eligible to purchase energy or related services in the PJM Interchange Energy Market. Market Buyers shall comply with all requirements for making purchases from the PJM Interchange Energy Market.

1.7.2A Economic Load Response Participants.

Only Economic Load Response Participants shall be eligible to participate in the Real-time Energy Market and the Day-ahead Energy Market by submitting offers to the Office of the Interconnection to reduce demand.

1.7.3 Agents.

A Market Participant may participate in the PJM Interchange Energy Market through an agent, provided that the Market Participant informs the Office of the Interconnection in advance in writing of the appointment of such agent. A Market Participant participating in the PJM Interchange Energy Market through an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the PJM Interchange Energy Market, and shall ensure that any such agent complies with the requirements of this Agreement.

1.7.4 General Obligations of the Market Participants.

(a) In performing its obligations to the Office of the Interconnection hereunder, each Market Participant shall at all times (i) follow Good Utility Practice, (ii) comply with all applicable laws and regulations, (iii) comply with the applicable principles, guidelines, standards and requirements of FERC, NERC and Applicable Regional Reliability Councils, (iv) comply with the procedures established for operation of the PJM Interchange Energy Market and PJM Region and (v) cooperate with the Office of the Interconnection as necessary for the operation of the PJM Region in a safe, reliable manner consistent with Good Utility Practice.

(b) Market Participants shall undertake all operations in or affecting the PJM Interchange Energy Market and the PJM Region including but not limited to compliance with all

Emergency procedures, in accordance with the power and authority of the Office of the Interconnection with respect to the operation of the PJM Interchange Energy Market and the PJM Region as established in this Agreement, and as specified in the Schedules to this Agreement and the PJM Manuals. Failure to comply with the foregoing operational requirements shall subject a Market Participant to such reasonable charges or other remedies or sanctions for non-compliance as may be established by the PJM Board, including legal or regulatory proceedings as authorized by the PJM Board to enforce the obligations of this Agreement.

(c) The Office of the Interconnection may establish such committees with a representative of each Market Participant, and the Market Participants agree to provide appropriately qualified personnel for such committees, as may be necessary for the Office of the Interconnection and PJMSettlement to perform its obligations hereunder.

(d) All Market Participants shall provide to the Office of the Interconnection the scheduling and other information specified in the Schedules to this Agreement, and such other information as the Office of the Interconnection may reasonably require for the reliable and efficient operation of the PJM Region and PJM Interchange Energy Market, and for compliance with applicable regulatory requirements for posting market and related information. Such information shall be provided as much in advance as possible, but in no event later than the deadlines established by the Schedules to this Agreement, or by the Office of the Interconnection in conformance with such Schedules. Such information shall include, but not be limited to, maintenance and other anticipated outages of generation or transmission facilities, scheduling and related information on bilateral transactions and self-scheduled resources, and implementation of active load management, interruption of load, Price Responsive Demand, and other load reduction measures. The Office of the Interconnection shall abide by appropriate requirements for the non-disclosure and protection of any confidential or proprietary information given to the Office of the Interconnection by a Market Participant. Each Market Participant shall maintain or cause to be maintained compatible information and communications systems, as specified by the Office of the Interconnection, required to transmit scheduling, dispatch, or other time-sensitive information to the Office of the Interconnection in a timely manner.

(e) Subject to the requirements for Economic Load Response Participants in section 1.5A above, each Market Participant shall install and operate, or shall otherwise arrange for, metering and related equipment capable of recording and transmitting all voice and data communications reasonably necessary for the Office of the Interconnection and PJMSettlement to perform the services specified in this Agreement. A Market Participant that elects to be separately billed for its PJM Interchange shall, to the extent necessary, be individually metered in accordance with Section 14 of this Agreement, or shall agree upon an allocation of PJM Interchange between it and the Market Participant through whose meters the unmetered Market Participant's PJM Interchange is delivered. The Office of the Interconnection shall be notified of the allocation by the foregoing Market Participants.

(f) Each Market Participant shall operate, or shall cause to be operated, any generating resources owned or controlled by such Market Participant that are within the PJM Region or otherwise supplying energy to or through the PJM Region in a manner that is

consistent with the standards, requirements or directions of the Office of the Interconnection and that will permit the Office of the Interconnection to perform its obligations under this Agreement; provided, however, no Market Participant shall be required to take any action that is inconsistent with Good Utility Practice or applicable law.

(g) Each Market Participant shall follow the directions of the Office of the Interconnection to take actions to prevent, manage, alleviate or end an Emergency in a manner consistent with this Agreement and the procedures of the PJM Region as specified in the PJM Manuals.

(h) Each Market Participant shall obtain and maintain all permits, licenses or approvals required for the Market Participant to participate in the PJM Interchange Energy Market in the manner contemplated by this Agreement.

(i) Consistent with Section 36.1.1 of the PJM Tariff, to the extent its generating facility is dispatchable, a Market Participant shall submit an Economic Minimum in the Real-time Energy Market that is no greater than the higher of its physical operating minimum or its Capacity Interconnection Rights, as that term is defined in the PJM Tariff, associated with such generating facility under its Interconnection Service Agreement under Attachment O of the PJM Tariff or a wholesale market participation agreement.

1.7.5 Market Operations Center.

Each Market Participant shall maintain a Market Operations Center, or shall make appropriate arrangements for the performance of such services on its behalf. A Market Operations Center shall meet the performance, equipment, communications, staffing and training standards and requirements specified in this Agreement for the scheduling and completion of transactions in the PJM Interchange Energy Market and the maintenance of the reliable operation of the PJM Region, and shall be sufficient to enable (i) a Market Seller or an Economic Load Response Participant to perform all terms and conditions of its offers to the PJM Interchange Energy Market, and (ii) a Market Buyer or an Economic Load Response Participant to conform to the requirements for purchasing from the PJM Interchange Energy Market.

1.7.6 Scheduling and Dispatching.

(a) The Office of the Interconnection shall schedule and dispatch in real-time generation resources and/or Demand Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Sellers, continuing until sufficient generation resources and/or Demand Resources are dispatched to serve the PJM Interchange Energy Market energy purchase requirements under normal system conditions of the Market Buyers (taking into account any reductions to such requirements in accordance with PRD Curves properly submitted by PRD Providers), as well as the requirements of the PJM Region for ancillary services provided by generation resources and/or Demand Resources, in accordance with this Agreement. Such scheduling and dispatch shall recognize transmission constraints on coordinated flowgates external to the Transmission System in

accordance with Appendix A to the Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38) and on other such flowgates that are coordinated in accordance with agreements between the LLC and other entities. Scheduling and dispatch shall be conducted in accordance with this Agreement.

(b) The Office of the Interconnection shall undertake to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the PJM Interchange Energy Market, and any relevant procedures of another Control Area, or any tariff (including the PJM Tariff). Upon determining that any such conflict or incompatibility exists, the Office of the Interconnection shall propose tariff or procedural changes, and undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

(c) To protect its generation or distribution facilities, or local Transmission Facilities not under the monitoring responsibility and dispatch control of the Office of the Interconnection, an entity may request that the Office of the Interconnection schedule and dispatch generation or reductions in demand to meet a limit on Transmission Facilities different from that which the Office of the Interconnection has determined to be required for reliable operation of the Transmission System. To the extent consistent with its other obligations under this Agreement, the Office of the Interconnection shall schedule and dispatch generation and reductions in demand in accordance with such request. An entity that makes a request pursuant to this section 1.7.6(c) shall be responsible for all generation and other costs resulting from its request that would not have been incurred by operating the Transmission System and scheduling and dispatching generation in the manner that the Office of the Interconnection otherwise has determined to be required for reliable operation of the Transmission System.

1.7.7 Pricing.

The price paid for energy bought and sold in the PJM Interchange Energy Market and for demand reductions will reflect the hourly Locational Marginal Price at each load and generation bus, determined by the Office of the Interconnection in accordance with this Agreement. Transmission Congestion Charges and Transmission Loss Charges, which shall be determined by differences in Congestion Prices and Loss Prices in an hour, shall be calculated by the Office of the Interconnection, and collected by PJMSettlement, and the revenues therefrom shall be disbursed by PJMSettlement in accordance with this Schedule.

1.7.8 Generating Market Buyer Resources.

A Generating Market Buyer may elect to self-schedule its generation resources up to that Generating Market Buyer's Equivalent Load, in accordance with and subject to the procedures specified in this Schedule, and the accounting and billing requirements specified in Section 3 to this Schedule. PJMSettlement shall not be a contracting party with respect to such self-scheduled or self-supplied transactions.

1.7.9 Delivery to an External Market Buyer.

A purchase of Spot Market Energy by an External Market Buyer shall be delivered to a bus or busses at the electrical boundaries of the PJM Region specified by the Office of the Interconnection, or to load in such area that is not served by Network Transmission Service, using Point-to-Point Transmission Service paid for by the External Market Buyer. Further delivery of such energy shall be the responsibility of the External Market Buyer.

1.7.10 Other Transactions.

(a) Bilateral Transactions.

(i) In addition to transactions in the PJM Interchange Energy Market, Market Participants may enter into bilateral contracts for the purchase or sale of electric energy to or from each other or any other entity, subject to the obligations of Market Participants to make Generation Capacity Resources available for dispatch by the Office of the Interconnection. Such bilateral contracts shall be for the physical transfer of energy to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its eSchedules and Enhanced Energy Scheduler tools.

(ii) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of energy to a Market Participant inside the PJM Region, title to the energy that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and the further transmission of the energy or further sale of the energy into the PJM Interchange Energy Market shall be transacted by the buyer under the bilateral contract. With respect to all bilateral contracts for the physical transfer of energy to an entity outside the PJM Region, title to the energy shall pass to the buyer at the border of the PJM Region and shall be delivered to the border using transmission service. In no event shall the purchase and sale of energy between Market Participants under a bilateral contract constitute a transaction in the PJM Interchange Energy Market or be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

(iii) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of energy reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the megawatt hours of such reported transactions to amounts reflecting the expected load and other physical delivery obligations of the buyer under the bilateral contract.

(iv) All payments and related charges for the energy associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. 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 a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

(v) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any Spot Market Backup used to meet the bilateral contract seller's obligation to deliver energy under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new eSchedules or Enhanced Energy Scheduler reporting by the Market Participant and (ii) terminate all of the Market Participant's eSchedules and Enhanced Energy Schedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the eSchedules and Enhanced Energy Schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection. PJMSettlement shall assign its claims against a seller with respect to a seller's nonpayment for Spot Market Backup to a buyer to the extent that the buyer has made an indemnification payment to PJMSettlement with respect to the seller's nonpayment.

(vi) Bilateral contracts that do not contemplate the physical transfer of energy to or from a Market Participant are not subject to this Schedule, shall not be reported to and coordinated with the Office of the Interconnection, and shall not in any way constitute a transaction in the PJM Interchange Energy Market.

(b) Market Participants shall have Spot Market Backup with respect to all bilateral transactions that contemplate the physical transfer of energy to or from a Market Participant, that are not dynamically scheduled pursuant to Section 1.12 and that are curtailed or interrupted for any reason (except for curtailments or interruptions through active load management for load located within the PJM Region).

(c) To the extent the Office of the Interconnection dispatches a Generating Market Buyer's generation resources, such Generating Market Buyer may elect to net the output of such resources against its hourly Equivalent Load. Such a Generating Market Buyer shall be deemed a buyer from the PJM Interchange Energy Market to the extent of its PJM Interchange Imports, and shall be deemed a seller to the PJM Interchange Energy Market to the extent of its PJM Interchange Exports.

(d) A Market Seller may self-supply Station Power for its generation facility in accordance with the following provisions:

(i) A Market Seller may self-supply Station Power for its generation facility during any month (1) when the net output of such facility is positive, or (2) when the net output of such facility is negative and the Market Seller during the same month has available at other of its generation facilities positive net output in an amount at least sufficient to offset fully such negative net output. For purposes of this subsection (d), "net output" of a generation facility during any month means the facility's gross energy

output, less the Station Power requirements of such facility, during that month. The determination of a generation facility's or a Market Seller's monthly net output under this subsection (d) will apply only to determine whether the Market Seller self-supplied Station Power during the month and will not affect the price of energy sold or consumed by the Market Seller at any bus during any hour during the month. For each hour when a Market Seller has positive net output and delivers energy into the Transmission System, it will be paid the LMP at its bus for that hour for all of the energy delivered. Conversely, for each hour when a Market Seller has negative net output and has received Station Power from the Transmission System, it will pay the LMP at its bus for that hour for all of the energy consumed.

(ii) Transmission Provider will determine the extent to which each affected Market Seller during the month self-supplied its Station Power requirements or obtained Station Power from third-party providers (including affiliates) and will incorporate that determination in its accounting and billing for the month. In the event that a Market Seller self-supplies Station Power during any month in the manner described in subsection (1) of subsection (d)(i) above, Market Seller will not use, and will not incur any charges for, transmission service. In the event, and to the extent, that a Market Seller self-supplies Station Power during any month in the manner described in subsection (2) of subsection (d)(i) above (hereafter referred to as "remote self-supply of Station Power"), Market Seller shall use and pay for transmission service for the transmission of energy in an amount equal to the facility's negative net output from Market Seller's generation facility(ies) having positive net output. Unless the Market Seller makes other arrangements with Transmission Provider in advance, such transmission service shall be provided under Part II of the PJM Tariff and shall be charged the hourly rate under Schedule 8 of the PJM Tariff for Non-Firm Point-to-Point Transmission Service with an election to pay congestion charges, provided, however, that no reservation shall be necessary for such transmission service and the terms and charges under Schedules 1, 1A, 2 through 6, 9 and 10 of the PJM Tariff shall not apply to such service. The amount of energy that a Market Seller transmits in conjunction with remote self-supply of Station Power will not be affected by any other sales, purchases, or transmission of capacity or energy by or for such Market Seller under any other provisions of the PJM Tariff.

(iii) A Market Seller may self-supply Station Power from its generation facilities located outside of the PJM Region during any month only if such generation facilities in fact run during such month and Market Seller separately has reserved transmission service and scheduled delivery of the energy from such resource in advance into the PJM Region.

1.7.11 Emergencies.

(a) The Office of the Interconnection, with the assistance of the Members' dispatchers as it may request, shall be responsible for monitoring the operation of the PJM Region, for declaring the existence of an Emergency, and for directing the operations of Market Participants as necessary to manage, alleviate or end an Emergency. The standards, policies and procedures of the Office of the Interconnection for declaring the existence of an Emergency,

including but not limited to a Minimum Generation Emergency, and for managing, alleviating or ending an Emergency, shall apply to all Members on a non-discriminatory basis. Actions by the Office of the Interconnection and the Market Participants shall be carried out in accordance with this Agreement, the NERC Operating Policies, Applicable Regional Reliability Council reliability principles and standards, Good Utility Practice, and the PJM Manuals. A declaration that an Emergency exists or is likely to exist by the Office of the Interconnection shall be binding on all Market Participants until the Office of the Interconnection announces that the actual or threatened Emergency no longer exists. Consistent with existing contracts, all Market Participants shall comply with all directions from the Office of the Interconnection for the purpose of managing, alleviating or ending an Emergency. The Market Participants shall authorize the Office of the Interconnection and PJMSettlement to purchase or sell energy on their behalf to meet an Emergency, and otherwise to implement agreements with other Control Areas interconnected with the PJM Region for the mutual provision of service to meet an Emergency, in accordance with this Agreement.

(b) To the extent load must be shed to alleviate an Emergency in a Control Zone, the Office of the Interconnection shall, to the maximum extent practicable, direct the shedding of load within such Control Zone. The Office of the Interconnection may shed load in one Control Zone to alleviate an Emergency in another Control Zone under its control only as necessary after having first shed load to the maximum extent practicable in the Control Zone experiencing the Emergency and only to the extent that PJM supports other control areas (not under its control) in those situations where load shedding would be necessary, such as to prevent isolation of facilities within the Eastern Interconnection, to prevent voltage collapse, or to restore system frequency following a system collapse; provided, however, that the Office of the Interconnection may not order a manual load dump in a Control Zone solely to address capacity deficiencies in another Control Zone. This section shall be implemented consistent with the North American Electric Reliability Council and applicable reliability council standards.

1.7.12 Fees and Charges.

Each Market Participant, except for Special Members, shall pay all fees and charges of the Office of the Interconnection for operation of the PJM Interchange Energy Market as determined by and allocated to the Market Participant by the Office of the Interconnection in accordance with Schedule 3.

1.7.13 Relationship to the PJM Region.

The PJM Interchange Energy Market operates within and subject to the requirements for the operation of the PJM Region.

1.7.14 PJM Manuals.

The Office of the Interconnection shall be responsible for maintaining, updating, and promulgating the PJM Manuals as they relate to the operation of the PJM Interchange Energy Market. The PJM Manuals, as they relate to the operation of the PJM Interchange Energy Market, shall conform and comply with this Agreement, NERC operating policies, and

Applicable Regional Reliability Council reliability principles, guidelines and standards, and shall be designed to facilitate administration of an efficient energy market within industry reliability standards and the physical capabilities of the PJM Region.

1.7.15 Corrective Action.

Consistent with Good Utility Practice, the Office of the Interconnection shall be authorized to direct or coordinate corrective action, whether or not specified in the PJM Manuals, as necessary to alleviate unusual conditions that threaten the integrity or reliability of the PJM Region, or the regional power system.

1.7.16 Recording.

Subject to the requirements of applicable State or federal law, all voice communications with the Office of the Interconnection Control Center may be recorded by the Office of the Interconnection and any Market Participant communicating with the Office of the Interconnection Control Center, and each Market Participant hereby consents to such recording.

1.7.17 Operating Reserves.

(a) The following procedures shall apply to any generation unit subject to the dispatch of the Office of the Interconnection for which construction commenced before July 9, 1996, or any Demand Resource subject to the dispatch of the Office of the Interconnection.

(b) The Office of the Interconnection shall schedule to the Operating Reserve and load-following objectives of the Control Zones of the PJM Region and the PJM Interchange Energy Market in scheduling generation resources and/or Demand Resources pursuant to this Schedule. A table of Operating Reserve objectives for each Control Zone is calculated and published annually in the PJM Manuals. Reserve levels are probabilistically determined based on the season's historical load forecasting error and forced outage rates.

(c) Nuclear generation resources shall not be eligible for Operating Reserve payments unless: 1) the Office of the Interconnection directs such resources to reduce output, in which case, such units shall be compensated in accordance with section 3.2.3(f) of this Schedule; or 2) the resource submits a request for a risk premium to the Market Monitoring Unit under the procedures specified in Section II.B of Attachment M - Appendix. A nuclear generation resource (i) must submit a risk premium consistent with its agreement under such process, or, (ii) if it has not agreed with the Market Monitoring Unit on an appropriate risk premium, may submit its own determination of an appropriate risk premium to the Office of the Interconnection, subject to acceptance by the Office of the Interconnection, with or without prior approval from the Commission.

(d) PJMSettlement shall be the Counterparty to the purchases and sales of Operating Reserve in the PJM Interchange Energy Market.

1.7.18 Regulation.

(a) Regulation to meet the Regulation objective of each Regulation Zone shall be supplied from generation resources and/or Demand Resources located within the metered electrical boundaries of such Regulation Zone. Generating Market Buyers, and Market Sellers offering Regulation, shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the PJM Manuals.

(b) The Office of the Interconnection shall obtain and maintain for each Regulation Zone an amount of Regulation equal to the Regulation objective for such Regulation Zone as specified in the PJM Manuals.

(c) The Regulation range of a generation unit or Demand Resource shall be at least twice the amount of Regulation assigned as described in the PJM Manuals.

(d) A ~~generation unit~~resource capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced by at least twice the amount of the Regulation provided with consideration of ~~. T~~the ~~amount of~~ Regulation ~~provided by a generation unit shall serve to redefine the Normal Minimum Generation and Normal Maximum Generation energy~~ limits of that ~~generation unit~~resource, ~~in that the amount of Regulation shall be added to the generation unit's Normal Minimum Generation energy limit, and subtracted from its Normal Maximum Generation energy limit~~ as specified in the PJM Manuals.

(e) Qualified Regulation must satisfy the measurement and verification tests described in the PJM Manuals.

1.7.19 Ramping.

A generator dispatched by the Office of the Interconnection pursuant to a control signal appropriate to increase or decrease the generator's megawatt output level shall be able to change output at the ramping rate specified in the Offer Data submitted to the Office of the Interconnection for that generator.

1.7.19A Synchronized Reserve.

(a) Synchronized Reserve shall be supplied from generation resources and/or Demand Resources located within the metered boundaries of the PJM Region. Generating Market Buyers, and Market Sellers offering Synchronized Reserve shall comply with applicable standards and requirements for Synchronized Reserve capability and dispatch specified in the PJM Manuals

(b) The Office of the Interconnection shall obtain and maintain for each Synchronized Reserve Zone an amount of Synchronized Reserve equal to the Synchronized Reserve objective for such Synchronized Reserve Zone, as specified in the PJM Manuals.

(c) The Synchronized Reserve capability of a generation resource and Demand Resource shall be the increase in energy output or load reduction achievable by the generation resource and Demand Resource within a continuous 10-minute period.

(d) A generation unit capable of automatic energy dispatch that also is providing Synchronized Reserve shall have its energy dispatch range reduced by the amount of the Synchronized Reserve provided. The amount of Synchronized Reserve provided by a generation unit shall serve to redefine the Normal Maximum Generation energy limit of that generation unit in that the amount of Synchronized Reserve provided shall be subtracted from its Normal Maximum Generation energy limit.

1.7.19B Bilateral Transactions Regarding Regulation, Synchronized Reserve and Day-ahead Scheduling Reserves.

(a) In addition to transactions in the Regulation market, Synchronized Reserve market, and Day-ahead Scheduling Reserves Market, Market Participants may enter into bilateral contracts for the purchase or sale of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from each other or any other entity. Such bilateral contracts shall be for the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its eMarket tools.

(b) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to a Market Participant in the PJM Region, title to the product that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and any further transactions associated with such products or further sale of such Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves in the markets for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves, respectively, shall be transacted by the buyer under the bilateral contract. In no event shall the purchase and sale of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves between Market Participants under a bilateral contract constitute a transaction in PJM's markets for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves, or otherwise be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

(c) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the amounts of such reported transactions to amounts reflecting the expected requirements for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves of the buyer pursuant to such bilateral contracts.

(d) All payments and related charges for the Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by 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 a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

(e) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any purchases by the seller under the bilateral contract in the markets for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves used to meet the bilateral contract seller's obligation to deliver Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new eMarket reporting by the Market Participant and (ii) terminate all of the Market Participant's reporting of eMarkets schedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the reported eMarkets schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection.

(f) Market Participants shall purchase Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves from PJM's markets for Regulation, Synchronized Reserve, Day-ahead Scheduling Reserves, in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason, with respect to all bilateral transactions that contemplate the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from a Market Participant.

1.7.20 Communication and Operating Requirements.

(a) Market Participants. Each Market Participant shall have, or shall arrange to have, its transactions in the PJM Interchange Energy Market subject to control by a Market Operations Center, with staffing and communications systems capable of real-time communication with the Office of the Interconnection during normal and Emergency conditions and of control of the Market Participant's relevant load or facilities sufficient to meet the requirements of the Market Participant's transactions with the PJM Interchange Energy Market, including but not limited to the following requirements as applicable.

(b) Market Sellers selling from generation resources and/or Demand Resources within the PJM Region shall: report to the Office of the Interconnection sources of energy available for operation; supply to the Office of the Interconnection all applicable Offer Data; report to the Office of the Interconnection generation resources and Demand Resources that are self-scheduled; with respect to generation resources, report to the Office of the Interconnection bilateral sales transactions to buyers not within the PJM Region; confirm to the Office of the Interconnection bilateral sales to Market Buyers within the PJM Region; respond to the Office of

the Interconnection's directives to start, shutdown or change output levels of generation units, or change scheduled voltages or reactive output levels of generation units, or reduce load from Demand Resources; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, generating equipment and Demand Resources are operated with control equipment functioning as specified in the PJM Manuals.

(c) Market Sellers selling from generation resources outside the PJM Region shall: provide to the Office of the Interconnection all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to Office of the Interconnection directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the Market Seller's Control Area.

(d) Market Participants that are Load Serving Entities or purchasing on behalf of Load Serving Entities shall: respond to Office of the Interconnection directives for load management steps; report to the Office of the Interconnection Generation Capacity Resources to satisfy capacity obligations that are available for pool operation; report to the Office of the Interconnection all bilateral purchase transactions; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(e) Market Participants that are not Load Serving Entities or purchasing on behalf of Load Serving Entities shall: provide to the Office of the Interconnection requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the PJM Interchange Energy Market, along with Dispatch Rate levels above which it does not desire to purchase; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(f) Economic Load Response Participants are responsible for maintaining demand reduction information, including the amount and price at which demand may be reduced. The Economic Load Response Participant shall provide this information to the Office of the Interconnection by posting it on the Load Response Program Registration link of the PJM website as required by the PJM Manuals. The Economic Load Response Participant shall notify the Office of the Interconnection of a demand reduction concurrent with, or prior to, the beginning of such demand reduction in accordance with the PJM Manuals. In the event that an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer that would affect a relevant Customer Baseline Load as required by the PJM Manuals.

(g) PRD Providers shall be responsible for ensuring automated reductions to their Price Responsive Demand in response to price in accordance with their PRD Curves submitted to the Office of the Interconnection.

1.10 Scheduling.

1.10.1 General.

(a) The Office of the Interconnection shall administer scheduling processes to implement a Day-ahead Energy Market and a Real-time Energy Market. PJMSettlement shall be the Counterparty to the purchases and sales of energy that clear the Day-ahead Energy Market and the Real-time Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a Generating Market Buyer's self-schedule or self-supply of its generation resources up to that Generating Market Buyer's Equivalent Load.

(b) The Day-ahead Energy Market shall enable Market Participants to purchase and sell energy through the PJM Interchange Energy Market at Day-ahead Prices and enable Transmission Customers to reserve transmission service with Transmission Congestion Charges and Transmission Loss Charges based on locational differences in Day-ahead Prices. Up-To Congestion transactions submitted in the Day-ahead Energy Market shall not require transmission service and Transmission Customers shall not reserve transmission service for such transactions. Market Participants whose purchases and sales, and Transmission Customers whose transmission uses are scheduled in the Day-ahead Energy Market, shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, at the applicable Day-ahead Prices for the amounts scheduled.

(c) In the Real-time Energy Market, Market Participants that deviate from the amounts of energy purchases or sales, or Transmission Customers that deviate from the transmission uses, scheduled in the Day-ahead Energy Market shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling shall be conducted as specified below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up

times greater than one day as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM Manuals.

1.10.1A Day-Ahead Energy Market Scheduling.

The following actions shall occur not later than 12:00 noon on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the Office of the Interconnection in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Schedule.

(a) Each Market Participant may submit to the Office of the Interconnection specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the PJM Manuals. Each Market Buyer shall inform the Office of the Interconnection of the prices, if any, at which it desires not to include its load in the Day-ahead Energy Market rather than pay the Day-ahead Price. PRD Providers that have committed Price Responsive Demand in accordance with the Reliability Assurance Agreement shall submit to the Office of the Interconnection, in accordance with procedures specified in the PJM Manuals, any desired updates to their previously submitted PRD Curves, provided that such updates are consistent with their Price Responsive Demand commitments, and provided further that PRD Providers that are not Load-Serving Entities for the Price Responsive Demand load at issue may only submit PRD Curves for the Real-time Energy Market. Price Responsive Demand that has been committed in accordance with the Reliability Assurance Agreement shall be presumed available for the next Operating Day in accordance with the most recently submitted PRD Curve unless the PRD Curve is updated to indicate otherwise. PRD Providers may also submit PRD Curves for any Price Responsive Demand that is not committed in accordance with the Reliability Assurance Agreement; provided that PRD Providers that are not Load-Serving Entities for the Price Responsive Demand load at issue may only submit PRD Curves for the Real-time Energy Market. All PRD Curves shall be on a PRD Substation basis, and shall specify the maximum time period required to implement load reductions.

(b) Each Generating Market Buyer shall submit to the Office of the Interconnection: (i) hourly schedules for resource increments, including hydropower units, self-scheduled by the Market Buyer to meet its Equivalent Load; and (ii) the Dispatch Rate at which each such self-scheduled resource will disconnect or reduce output, or confirmation of the Market Buyer's intent not to reduce output.

(c) All Market Participants shall submit to the Office of the Interconnection schedules for any bilateral transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection whether the transaction is to be included in the Day-ahead Energy Market. Any Market Participant that elects to include a bilateral transaction in the Day-ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the PJM Manuals), if any, at which it will be

wholly or partially curtailed rather than pay Transmission Congestion Charges. The foregoing price specification shall apply to the price difference between the specified bilateral transaction source and sink points in the day-ahead scheduling process only. Any Market Participant that elects not to include its bilateral transaction in the Day-ahead Energy Market shall inform the Office of the Interconnection if the parties to the transaction are not willing to incur Transmission Congestion Charges in the Real-time Energy Market in order to complete any such scheduled bilateral transaction. Scheduling of bilateral transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

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

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

iii) In addition to the foregoing schedules for bilateral transactions, Market Participants shall submit confirmations of each scheduled bilateral transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(d) Market Sellers wishing to sell into the Day-ahead Energy Market shall submit offers for the supply of energy (including energy from hydropower units), demand reductions, Regulation, Operating Reserves or other services for the following Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Attachment DD of the PJM Tariff, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. The submission of offers for resource increments that have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, and PJM Manuals, as applicable. Energy offered from generation resources that have not cleared a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region. The foregoing offers:

i) Shall specify the Generation Capacity Resource or Demand Resource and energy or demand reduction amount, respectively, for each hour in the offer period, and the minimum run time for generation resources and minimum down time for Demand Resources;

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

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

iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;

v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with a second schedule applicable if accepted after the foregoing deadline;

vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer, which offer shall remain open through the Operating Day for which the offer is submitted;

vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day; and

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

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation that shall specify the megawatt of Regulation being offered, which must equal or exceed 0.1 megawatts, the Regulation Zone for which such regulation is offered, the price of the capability offer in dollars per MW~~h~~, the price of the performance offer in Dollars per change in MW, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the resource's opportunity costs. The ~~price of the offer~~ total of the performance offer multiplied by the historical average mileage used in the market clearing plus the capability offer shall not exceed $100 per MWh in the case of Regulation offered for all Regulation Zones. In addition to any market-based offer for Regulation, the Market Seller also shall submit a cost-based offer. A cost-based offer must be in the form specified in the PJM Manuals and consist of the following components as well as any other components specified in the PJM Manuals:

i. The costs (in $/MW) of the fuel cost increase due to the heat rate increase resulting from operating a unit at lower megawatt output incurred from the provision of Regulation;

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

iii. An adder of up to $12.00 per megawatt of Regulation provided applied to the capability offer.

Qualified Regulation capability must satisfy the measurement and verification tests specified in the PJM Manuals.

(f) Each Market Seller owning or controlling the output of a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative shall submit a forecast of the availability of each such Generation Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with start-up and no-load fees, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours.

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

(h) The Office of the Interconnection shall post the total hourly loads scheduled in the Day-ahead Energy Market, as well as, its estimate of the combined hourly load of the Market Buyers for the next four days, and peak load forecasts for an additional three days.

(i) Except for Economic Load Response Participants, all Market Participants may submit Increment Bids and/or Decrement Bids that apply to the Day-ahead Energy Market only. Such bids must comply with the requirements set forth in the PJM Manuals and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-ahead Energy Market. The Office of the Interconnection may require that a market participant shall not submit in excess of 3000 bid/offer segments in the Day-ahead Energy Market, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to 10:00 a.m. EPT on the day that the Day-ahead Energy Market will clear. For purposes of this provision, a bid/offer segment is each pairing of price and megawatt quantity submitted as part of an Increment Bid or Decrement Bid.

(j) A Market Seller that wishes to make a generation resource or Demand Resource available to sell Synchronized Reserve shall submit an offer for Synchronized Reserve that shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.1

megawatts, the price of the offer in dollars per megawatt hour, and such other information specified by the Office of Interconnection as may be necessary to evaluate the offer and the energy used by the generation resource to provide the Synchronized Reserve and the generation resource's unit specific opportunity costs. The price of the offer shall not exceed the variable operating and maintenance costs for providing Synchronized Reserve plus seven dollars and fifty cents.

(k) An Economic Load Response Participant that wishes to participate in the Day-ahead Energy Market by reducing demand shall submit an offer to reduce demand to the Office of the Interconnection. The offer must equal or exceed 0.1 megawatts, and the offer shall specify: (i) the amount of the offered curtailment in minimum increments of .1 megawatts: (ii) the Day-ahead Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, start-up costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum of number of contiguous hours for which the load reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs).

(l) Market Sellers owning or controlling the output of a Demand Resource that was committed in an FRR Capacity Plan, self-supplied or offered and cleared in the Base Residual Auction or one of the Incremental Auctions, or owning or controlling the output of an ILR resource which was certified as specified in Attachment DD of the PJM Tariff, may submit demand reduction bids for the available load reduction capability of the Demand Resource or ILR resource. The submission of demand reduction bids for resource increments that have not cleared in the Base Residual Auction or in one of the Incremental Auctions, or for ILR resources that were not certified, or were not committed in an FRR Capacity Plan, shall be optional, but any such bids must contain the information specified in the PJM Economic Load Response Program to be included in such bids. A Demand Resource that was committed in an FRR Capacity plan, self-supplied or offered and cleared in a Base Residual Auction or an Incremental Auction may submit a demand reduction bid in the Day-ahead Energy Market as specified in the Economic Load Response Program, provided however, that in the event of an Emergency, PJM shall require Demand Resources and ILR resources to reduce load notwithstanding that the Zonal LMP at the time such Emergency is declared is below the price identified in the demand reduction bid.

(m) Market Sellers that wish to make Day-ahead Scheduling Reserves Resources available to sell Day-ahead Scheduling Reserves shall submit offers, each of which must equal or exceed 0.1 megawatts, in the Day-ahead Scheduling Reserves Market specifying: 1) the price of the offer in dollars per megawatt hour; and 2) such other information specified by the Office of the Interconnection as may be necessary to determine any relevant opportunity costs for the resource(s). The foregoing notwithstanding, to qualify to submit offers pursuant to this section, the Day-ahead Scheduling Reserves Resources shall submit energy offers in the Day-ahead Energy Market including start-up and shut-down costs for generation resource and Demand Resources, respectively, and all generation resources that are capable of providing Day-ahead Scheduling Reserves that a particular resource can provide that service. The MW quantity of

Day-Ahead Scheduling Reserves that a particular resource can provide in a given hour will be determined based on the energy Offer Data submitted in the Day-ahead Energy Market, as detailed in the PJM Manuals.

1.10.2 Pool-Scheduled Resources.

Pool-scheduled resources are those resources for which Market Participants submitted offers to sell energy in the Day-ahead Energy Market and offers to reduce demand in the Day-ahead Energy Market, which the Office of the Interconnection scheduled in the Day-ahead Energy Market as well as generators committed by the Office of the Interconnection subsequent to the Day-ahead Energy Market. Such resources shall be committed to provide energy in the real-time dispatch unless the schedules for such units are revised pursuant to Sections 1.10.9 or 1.11. Pool-scheduled resources shall be governed by the following principles and procedures.

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, start-up, no-load and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in Section 1.10.1A.

(b) A resource that is scheduled by a Market Participant to support a bilateral sale, or that is self-scheduled by a Generating Market Buyer, shall not be selected by the Office of the Interconnection as a pool-scheduled resource except in an Emergency.

(c) Market Sellers offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the Office of the Interconnection that is sufficient to enable the Office of the Interconnection to determine the available operating hours of such facilities.

(d) The Market Seller of a resource selected as a pool-scheduled resource shall receive payments or credits for energy, demand reductions or related services, or for start-up and no-load fees, from the Office of the Interconnection on behalf of the Market Buyers in accordance with Section 3 of this Schedule 1. Alternatively, the Market Seller shall receive, in lieu of start-up and no-load fees, its actual costs incurred, if any, up to a cap of the resource's start-up cost, if the Office of the Interconnection cancels its selection of the resource as a pool-scheduled resource and so notifies the Market Seller before the resource is synchronized.

(e) Market Participants shall make available their pool-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone.

(f) Economic Load Response Participants offering to reduce demand shall specify: (i) the amount of the offered curtailment, which offer must equal or exceed 0.1 megawatts, in minimum increments of .1 megawatts; (ii) the real-time Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, shut-down costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum number of contiguous hours for which the load

reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Real-time Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs). Economic Load Response Participants offering to reduce demand shall also indicate the hours that the demand reduction is not available.

1.10.3 Self-scheduled Resources.

Self-scheduled resources shall be governed by the following principles and procedures.

(a) Each Generating Market Buyer shall use all reasonable efforts, consistent with Good Utility Practice, not to self-schedule resources in excess of its Equivalent Load.

(b) The offered prices of resources that are self-scheduled, or otherwise not following the dispatch orders of the Office of the Interconnection, shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.

(c) Market Participants shall make available their self-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone, by submitting an offer as to such resources.

(d) A Market Participant self-scheduling a resource in the Day-ahead Energy Market that does not deliver the energy in the Real-time Energy Market, shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

1.10.4 Capacity Resources.

(a) A Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that is selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection. Such a Generation Capacity Resource that does not deliver energy as scheduled shall be deemed to have experienced a Generator Forced Outage to the extent of such energy not delivered. A Market Participant offering such Generation Capacity Resource in the Day-ahead Energy Market shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Energy from a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that has not been scheduled in the Day-ahead Energy Market may be sold on a bilateral basis by the Market Seller, may be self-scheduled, or may be offered for dispatch during the Operating Day in accordance with the procedures specified in this Schedule. Such a Generation Capacity Resource that has not been scheduled in the Day-ahead Energy Market and that has been sold on a bilateral basis must be made available upon request to the Office of the Interconnection for scheduling and dispatch during the Operating Day if the

Office of the Interconnection declares a Maximum Generation Emergency. Any such resource so scheduled and dispatched shall receive the applicable Real-time Price for energy delivered.

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

1.10.5 External Resources.

(a) External Resources may submit offers to the PJM Interchange Energy Market, in accordance with the day-ahead and real-time scheduling processes specified above. An External Resource selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection, and except as specified below shall be compensated on the same basis as other pool-scheduled resources. External Resources that are not capable of dynamic dispatch shall, if selected by the Office of the Interconnection on the basis of the Market Seller's Offer Data, be block loaded on an hourly scheduled basis. Market Sellers shall offer External Resources to the PJM Interchange Energy Market on either a resource-specific or an aggregated resource basis. A Market Participant whose pool-scheduled resource does not deliver the energy scheduled in the Day-ahead Energy Market shall replace such energy not delivered as scheduled in the Day-ahead Energy Market with energy from the PJM Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Offers for External Resources from an aggregation of two or more generating units shall so indicate, and shall specify, in accordance with the Offer Data requirements specified by the Office of the Interconnection: (i) energy prices; (ii) hours of energy availability; (iii) a minimum dispatch level; (iv) a maximum dispatch level; and (v) unless such information has previously been made available to the Office of the Interconnection, sufficient information, as specified in the PJM Manuals, to enable the Office of the Interconnection to model the flow into the PJM Region of any energy from the External Resources scheduled in accordance with the Offer Data.

(c) Offers for External Resources on a resource-specific basis shall specify the resource being offered, along with the information specified in the Offer Data as applicable.

1.10.6 External Market Buyers.

(a) Deliveries to an External Market Buyer not subject to dynamic dispatch by the Office of the Interconnection shall be delivered on a block loaded basis to the bus or busses at the electrical boundaries of the PJM Region, or in such area with respect to an External Market Buyer's load within such area not served by Network Service, at which the energy is delivered to or for the External Market Buyer. External Market Buyers shall be charged (which charge may be positive or negative) at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing bus or busses.

(b) An External Market Buyer's hourly schedules for energy purchased from the PJM Interchange Energy Market shall conform to the ramping and other applicable requirements of

the interconnection agreement between the PJM Region and the Control Area to which, whether as an intermediate or final point of delivery, the purchased energy will initially be delivered.

(c) The Office of the Interconnection shall curtail deliveries to an External Market Buyer if necessary to maintain appropriate reserve levels for a Control Zone as defined in the PJM Manuals, or to avoid shedding load in such Control Zone.

1.10.6A Transmission Loading Relief Customers.

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

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

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

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

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

1.10.7 Bilateral Transactions.

Bilateral transactions as to which the parties have notified the Office of the Interconnection by the deadline specified in Section 1.10.1A that they elect not to be included in the Day-ahead Energy Market and that they are not willing to incur Transmission Congestion Charges in the Real-time Energy Market shall be curtailed by the Office of the Interconnection as necessary to reduce or alleviate transmission congestion. Bilateral transactions that were not included in the Day-ahead Energy Market and that are willing to incur congestion charges and bilateral transactions that were accepted in the Day-ahead Energy Market shall continue to be implemented during periods of congestion, except as may be necessary to respond to Emergencies.

1.10.8 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers and PRD Curves properly submitted by Load Serving Entities for the Price Responsive Demand loads they serve; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv) the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) Not earlier than 4:00 p.m. of the day before each Operating Day, or such other deadline as may be specified by the Office of the Interconnection in the PJM Manuals, the Office of the Interconnection shall: (i) post the aggregate Day-ahead Energy Market results; (ii) post the Day-ahead Prices; and (iii) inform the Market Sellers, Market Buyers, and Economic Load Response Participants of their scheduled injections, withdrawals, and demand reductions respectively.

(c) Following posting of the information specified in Section 1.10.8(b), the Office of the Interconnection shall revise its schedule of generation resources to reflect updated projections of load, conditions affecting electric system operations in the PJM Region, the availability of and constraints on limited energy and other resources, transmission constraints, and other relevant factors.

(d) Market Buyers shall pay PJMSettlement and Market Sellers shall be paid by PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the offer that set the Day-ahead Price is positive. Market Buyers shall be paid by PJMSettlement and Market Sellers shall pay PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the offer that set the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Section 3.3A of this Schedule.

(e) If the Office of the Interconnection discovers an error in prices and/or cleared quantities in the Day-ahead Energy Market, Real-time Energy Market, Ancillary Services Markets or Day Ahead Scheduling Reserve Market after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 12:00 p.m. of the second business day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the second business day following the initial publication of the results for the Day-ahead Scheduling Reserve Market and Day-ahead Energy Market.

After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the fifth business day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the fifth business day following the initial publication of the results in the Day-ahead Scheduling Reserve Market and the Day-ahead Energy Market. Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating Day for the Ancillary Services Markets, Day-ahead Energy Market and Real-time Energy Market, and no later than 5:00 p.m. of the tenth calendar day following the initial publication of the results in the Day-ahead Scheduling Reserve Market. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced market results are under publicly noticed review by the FERC.

(f) Consistent with Section 18.17.1 of the PJM Operating Agreement, and notwithstanding anything to the contrary in the Operating Agreement or in the PJM Tariff, to allow the tracking of Market Participants' non-aggregated bids and offers over time as required by FERC Order No. 719, the Office of the Interconnection shall post on its Web site the non-aggregated bid data and Offer Data submitted by Market Participants (for participation in the PJM Interchange Energy Market) approximately four months after the bid or offer was submitted to the Office of the Interconnection.

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, a generation rebidding period shall exist from 4:00 p.m. to 6:00 p.m. on the day before each Operating Day. During the rebidding period, Market Participants may submit revisions to generation Offer Data for any generation resource that was not selected as a pool-scheduled resource in the Day-ahead Energy Market. Adjustments to Day-ahead Energy Markets shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 60 minutes prior to the hour in which the adjustment is to take effect, as follows:

i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;

ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or

iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or

iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any start-up fee.

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

(d) An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase in the Day-ahead Energy Market by notifying the Office of the Interconnection of the adjustment in deliveries not later than 60 minutes prior to the hour in which the adjustment is to take effect, but any such adjustment shall not affect the obligation of the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(e) For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section 1.10, the Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules for the hour.

1.11 Dispatch.

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

1.11.1 Resource Output.

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

1.11.2 Operating Basis.

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

1.11.3 Pool-dispatched Resources.

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

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

1.11.3A Maximum Generation Emergency.

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

1.11.4 Regulation.

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

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

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

1.11.4A Synchronized Reserve.

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

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

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

1.11.5 PJM Open Access Same-time Information System.

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

2.2 General.

The Office of the Interconnection shall determine the least cost security-constrained dispatch, which is the least costly means of serving load and meeting reserve requirements at different locations in the PJM Region based on actual operating conditions existing on the power grid (including transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6) and on the prices at which Market Sellers have offered to supply energy and offers by Economic Load Response Participants to reduce demand that qualify to set Locational Marginal Prices in the PJM Interchange Energy Market. Locational Marginal Prices for the generation and load busses in the PJM Region, including interconnections with other Control Areas, will be calculated based on the actual economic dispatch and the prices of energy and demand reduction offers. The process for the determination of Locational Marginal Prices shall be as follows:

(a) To determine actual operating conditions on the power grid in the PJM Region, the Office of the Interconnection shall use a computer model of the interconnected grid that uses available metered inputs regarding generator output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network. The computer model employed for this purpose, referred to as the State Estimator program, is a standard industry tool and is described in Section 2.3 below. It will be used to obtain information regarding the output of generation supplying energy to the PJM Region, loads at busses in the PJM Region, transmission losses, and power flows on binding transmission constraints for use in the calculation of Locational Marginal Prices. Additional information used in the calculation, including Dispatch Rates and real time schedules for external transactions between PJM and other Control Areas and dispatch and pricing information from entities with whom PJM has executed a joint operating agreement, will be obtained from the Office of the Interconnection's dispatchers.

(b) Using the prices at which energy is offered by Market Sellers and demand reductions are offered by Economic Load Response Participants to the PJM Interchange Energy Market, the Office of the Interconnection shall determine the offers of energy and demand reductions that will be considered in the calculation of Locational Marginal Prices. As described in Section 2.4 below, every qualified offer for demand reduction and of energy by a Market Seller from resources that are following economic dispatch instructions of the Office of the Interconnection will be utilized in the calculation of Locational Marginal Prices, including, without limitation, qualified offers from Economic Load Response Participants in either the Day-Ahead or Real-Time Energy Markets that satisfy the Net Benefits Test. Offers of demand reduction from Demand Resources in the Real-time Energy Market will not be eligible to set Locational Marginal Prices, unless metered directly by the Office of the Interconnection.

(c) Based on the system conditions on the PJM power grid, determined as described in (a), and the eligible energy and demand reduction offers, determined as described in (b), the Office of the Interconnection shall determine the least costly means of obtaining energy to serve

the next increment of load at each bus in the PJM Region, in the manner described in Section 2.5 below. The result of that calculation shall be a set of Locational Marginal Prices based on the system conditions at the time.

2.3 Determination of System Conditions Using the State Estimator.

Power system operations, including, but not limited to, the determination of the least costly means of serving load and meeting reserve requirements, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In calculating Locational Marginal Prices, the Office of the Interconnection shall obtain a complete and consistent description of conditions on the electric network in the PJM Region by using the most recent power flow solution produced by the State Estimator program and utilized in the PJM dispatch algorithm, which State Estimator program is also used by the Office of the Interconnection for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available real-time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at busses for which real-time information is unavailable. The Office of the Interconnection shall obtain a State Estimator solution every five minutes, which shall provide the megawatt output of generators and the loads at busses in the PJM Region, transmission line losses, and actual flows or loadings on constrained transmission facilities. External transactions between PJM and other Control Areas shall be included in the Locational Marginal Price calculation on the basis of the real time transaction schedules implemented by the Office of the Interconnection's dispatcher.

2.5 Calculation of Real-time Prices.

(a) The Office of the Interconnection shall determine the least costly means of obtaining energy to serve the next increment of load (taking account of any applicable and available load reductions indicated on PRD Curves properly submitted by any PRD Provider) at each bus in the PJM Region represented in the State Estimator and each Interface Pricing Point between PJM and an adjacent Control Area, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and utilized in the PJM dispatch algorithm and the energy offers that are the basis for the Day-ahead Energy Market, or that are determined to be eligible for consideration under Section 2.4 in connection with the real-time dispatch, as applicable. This calculation shall be made by applying ~~an incremental linear optimization method to minimize energy costs~~ a real-time joint optimization of energy and reserves, given actual system conditions, a set of energy offers, a set of reserve offers, a set of Reserve Penalty Factors, and any binding transmission constraints that may exist. In performing this calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a generation resource or decrease an increment of energy being consumed by a Demand Resource, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses. The real-time Locational Marginal Prices at a bus shall be determined through the joint optimization based on the lowest marginal cost to serve the next increment of load at the bus taking into account the applicable reserve requirements, unit resource constraints, transmission constraints and marginal loss impact.~~The energy offer or offers that can serve an increment of load at a bus at the lowest cost, calculated in this manner, shall determine the Real-time Price at that bus.~~

(b) If PJM is able to meet its Synchronized Reserve requirements as specified in 1.7.19A, real-time Locational Marginal Prices shall be calculated as described in Section 2.5(a) above. When Synchronized Reserve requirements cannot be met, the real-time Locational Marginal Prices shall be calculated in accordance with 2.5(a) above and Section 6A of this Schedule 1.

(~~b~~c) During the Operating Day, the calculation set forth in (a) shall be performed every five minutes, using the Office of the Interconnection's Locational Marginal Price program, producing a set of Real-time Prices based on system conditions during the preceding interval. The prices produced at five-minute intervals during an hour will be integrated to determine the Real-time Prices for that hour.

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 ~~at~~: (i) the capability Regulation market-clearing price determined in accordance with subsection (~~c~~g) of this section; ~~, plus~~ the amounts, if any, described in subsection (~~f~~e) of this section; and (iii) the Internal Market Buyer's pro rata share of any performance credits paid to regulating resources calculated in accordance with subsection (f) of this section.

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

(c) If PJM is able to meet its Synchronized Reserve requirements as specified in 1.7.19A, ~~The~~ 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 (f) 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 ~~highest sum of a resource's Regulation offer plus its estimated~~ unit-specific opportunity costs, during the 5-minute period determined as described in subsection (d) below from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.3.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation 5-minute ~~market~~ clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell

Regulation in each regulating hour shall be equal to ~~the sum of the unit-specific opportunity costs (i) incurred during the hour in which the obligation is fulfilled, plus costs (ii) associated with uneconomic operation during the hour preceding the initial regulating hour ("preceding shoulder hour"), plus costs (iii) associated with uneconomic operation during the hour after the final regulating hour ("following shoulder hour").~~

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

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

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

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

~~(e) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour~~

~~in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's Regulation signals from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.~~

~~The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.~~

~~The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the following shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the following shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the following shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.~~

(~~f~~e) 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.

(f) 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 expected amount of Regulation that resource will be dispatched based on the historical ratio of control signals calculated by the Office of the Interconnection, and the ratio of benefits to system control for following the Regulation control signal 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 based on the assigned MW(s), the performance Regulation market-clearing price, the amount of Regulation performance of the resource provides during the market hour, and the accuracy with which each resource responds to the Office of the Interconnection's Regulation signals during the market hour.

(g) 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 (f) 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 capacity Regulation market-clearing price.

(h) 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.

(i) If PJM is unable to meet its Synchronized Reserve requirements as specified in 1.7.19A, the performance Regulation clearing price and the capability Regulation clearing price will be held steady for the duration of the reserve deficiency at the last value calculated prior to the start of the reserve deficiency. In the event of such reserve deficiency, 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 at the higher of (i) the Regulation market-clearing price in such Regulation Zone or (ii) the sum of the regulation offer and the unit-specific opportunity cost of the generation resource supplying the increment of Regulation.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to section 1.10.1A(e) of this Schedule. A Regulation supplier fails the three-pivotal supplier test in any hour in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

(b) For the purposes of conducting the three-pivotal supplier test pursuant to this section, the following applies:

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region for which the 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.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Section 3.2.3A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the Day-ahead Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load

fees and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve credits, identified as RA Credits for Reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall

be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

(c) The sum of the foregoing credits calculated in accordance with Section 3.2.3(b) plus any unallocated charges from Section 3.2.3(h) and 5.1.7 and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of Operating Reserves in the Day-ahead Energy Market.

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following segments: 1) the greater of their day-ahead schedules or minimum run time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or minimum run time (minimum down time for Demand Resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time (minimum down time for Demand Resources) and Segment 2 will include the remainder of the contiguous hours when the

resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

Credits received pursuant to this section shall be equal to the positive difference between a resource's total offered price for start-up (shutdown costs for Demand Resources) and no-load fees and energy, determined on the basis of the resource's scheduled output, and the total value of the resource's energy as determined by the Real-time Energy Market and the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for segment 2 shall exclude start up (shutdown costs for Demand Resources) costs for generation resources.

Except as provided in Section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to Section 3.2.3(b) plus the resource's opportunity cost and less any amounts credited for Synchronized Reserve in excess of the Synchronized Reserve offer plus the resource's opportunity cost and less any amounts credited for Reactive Services as specified in Section 3.2.3.B, and less any amounts for Day-ahead Scheduling Reserve in excess of the Day-ahead Scheduling Reserve offer plus the resource's opportunity cost, shall be credited to the Market Seller.

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

(f) A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

AG equals the actual hourly integrated output of the unit;

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

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

where URTLMP - UB shall not be negative.

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

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described above for a steam unit or combined cycle unit operating in combined cycle mode.

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

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

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

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

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

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

(f-2) A Market Seller's hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Section 1.10.2(d) such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves, plus any redispatch costs incurred in accordance with section 10(a) of this Schedule, shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (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 area pursuant to Section 1.12.

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 Regions, as defined in Section 3.2.3(q) of this Schedule, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with Section 3.2.3(q). Deviations at interfaces and hubs shall be associated with the Eastern or Western Region if all the busses that

define all interfaces or all hubs are located in the region. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by busses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed in accordance with the following provisions:

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of an Operating Reserve shortage in real-time or where PJM initiates the request for load reductions in real-time in order to avoid an Operating Reserve shortage as described in this Schedule, Section 6A, Scarcity Pricing.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in Section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for of the PJM Region.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to

load outside the PJM Region pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared ("Maximum Generation Emergency Alert"); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the Operating Reserves credit otherwise provided by Section 3.2.3.(b) or Section 3.2.3(e) in connection with market-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as "MaxGen Conditions"). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Schedule 2 of the Operating Agreement, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatt hours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any hours required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh,

regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described in the PJM Manuals. Ramp-limited desired MW values shall be used to determine generation resource real-time deviations from the resource's day-ahead schedules.

The Office of the Interconnection shall calculate a ramp-limited desired MW value for generation resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:

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

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

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

$$RL_Desired_t = AOutput_{t-1} + \left(Ramp_Request_t * Case_Eff_time_{t-1} \right)$$

where:

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

To determine if a 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 <= 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 n 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 to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve charges shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve charges shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve charges shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time

during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region. For the purposes of this section, the Western Region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, DEOK transmission Zones, and the Eastern Region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones. The regional balancing Operating Reserve rates shall be determined in accordance with the following provisions:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

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

(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.

3.2.3A Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Synchronized Reserve Zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Synchronized Reserve Zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). An Internal Market Buyer that does

not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts if any, described in subsections (g), (h) and (i) of this section.

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

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

ii) Credits for Synchronized Reserve provided by generation resources that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the Interconnection energy dispatch signals and instructions ("Tier 2 Synchronized Reserve") shall be the higher of (i) the Synchronized Reserve Market Clearing Price or (ii) the sum of (A) the Synchronized Reserve offer, and (B) the specific opportunity cost of the generation resource supplying the increment of Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

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

(c) The Synchronized Reserve Energy Premium Price is the average of the five-minute Locational Marginal Prices calculated during the Synchronized Reserve Event plus an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

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

(e) In determining the 5-minute Synchronized Reserve ~~Market Clearing~~ clearing ~~Price~~price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the expected Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

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

(g) Charges for Tier 1 Synchronized Reserve will be allocated in proportion to the amount of Tier 1 Synchronized Reserve applied to each Synchronized Reserve Obligation. In the event Tier 1 Synchronized Reserve is provided by a Market Seller in excess of that Market Seller's Synchronized Reserve Obligation, the remainder of the Tier 1 Synchronized Reserve that is not utilized to fulfill the Seller's obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

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

(i) In the event the Office of the Interconnection needs to assign more Tier 2 Synchronized Reserve during an hour than was estimated as needed at the time the Synchronized Reserve Market Clearing Price was calculated for that hour due to a reduction in available Tier 1

Synchronized Reserve, the costs of the excess Tier 2 Synchronized Reserve shall be allocated and charged to those providers of Tier 1 Synchronized Reserve whose available Tier 1 Synchronized Reserve was reduced from the needed amount estimated during the Synchronized Reserve Market Clearing Price calculation, in proportion to the amount of the reduction in Tier 1 Synchronized Reserve availability.

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

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l) is the difference between the generation resource's output or the Demand Resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load Demand Resource's consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.

(m) If PJM is unable to meet its Synchronized Reserve requirements as specified in 1.7.19A, the Synchronized Reserve Market Clearing Price will be held steady for the duration of the reserve deficiency at the last value calculated prior to the start of the reserve deficiency.

3.2.3A.01 Day-ahead Scheduling Reserves.

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

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

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

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

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

(iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time

the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

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

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

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

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch

algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit hourly in an amount equal to {(LMPDMW - AG) x (URTLMP - UB)}

where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

AG equals the actual hourly integrated output of the unit;

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

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

where URTLMP - UB shall not be negative.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be

credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

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

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

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

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

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

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

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to Section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit hourly in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual hourly integrated output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

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

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

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generating unit's bus, (C) the generating unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generating resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the

PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generating unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to paragraph (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to section (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on

whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

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

3.2.5 Transmission Loss Charges.

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

3.2.6 Emergency Energy.

(a) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each hour of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(b) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each hour of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(c) The net costs or net revenues associated with sales or purchases of hourly energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each hour of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Buyer in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market Buyer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Buyer's internal accounting.

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

Definitions Q - R

1.38.01 Regional RTEP Project.

"Regional RTEP Project" shall mean a transmission expansion or enhancement rated at 230 kV or above which is required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.

1.38.01A Relevant Electric Retail Regulatory Authority:

An entity that has jurisdiction over and establishes prices and policies for competition for providers of retail electric service to end-customers, such as the city council for a municipal utility, the governing board of a cooperative utility, the state public utility commission or any other such entity.

1.38A Regulation Zone.

"Regulation Zone" shall mean any of those one or more geographic areas, each consisting of a combination of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, regulation service.

1.39 Related Parties.

"Related Parties" shall mean, solely for purposes of the governance provisions of this Agreement: (i) any generation and transmission cooperative and one of its distribution cooperative members; and (ii) any joint municipal agency and one of its members. For purposes of this Agreement, representatives of state or federal government agencies shall not be deemed Related Parties with respect to each other, and a public body's regulatory authority, if any, over a Member shall not be deemed to make it a Related Party with respect to that Member.

1.40 Reliability Assurance Agreement.

"Reliability Assurance Agreement" shall mean that certain Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region, on file with FERC as PJM Interconnection, L.L.C. Rate Schedule FERC. No .42, establishing obligations, standards and procedures for maintaining the reliable operation of the PJM Region.

1.40A [Reserved].

1.40B [Reserved].

Definitions S – T

1.40C SERC.

"SERC" or "Southeastern Electric Reliability Council" shall mean the reliability council under section 202 of the Federal Power Act established pursuant to the SERC Agreement dated January 14, 1970, or any successor thereto.

1.41 Sector Votes.

"Sector Votes" shall mean the affirmative and negative votes of each sector of a Senior Standing Committee, as specified in Section 8.4.

1.41A Senior Standing Committees.

"Senior Standing Committees" shall mean the Members Committee, and the Markets, and Reliability Committee, as established in Sections 8.1 and 8.6.

1.41A.01 [Reserved].

1.41A.02 [Reserved].

1.41A.03 [Reserved].

1.41B Standing Committees.

"Standing Committees" shall mean the Members Committee, the committees established and maintained under Section 8.6, and such other committees as the Members Committee may establish and maintain from time to time.

1.42 State.

"State" shall mean the District of Columbia and any State or Commonwealth of the United States.

1.42.01 State Certification.

"State Certification" shall mean the Certification of an Authorized Commission, pursuant to Section 18 of this Agreement, the form of which is appended to this Agreement as Schedule 10A, wherein the Authorized Commission identifies all Authorized Persons employed or retained by such Authorized Commission, a copy of which shall be filed with FERC.

1.42A State Consumer Advocate.

"State Consumer Advocate" shall mean a legislatively created office from any State, all or any part of the territory of which is within the PJM Region, and the District of Columbia established, inter alia, for the purpose of representing the interests of energy consumers before the utility regulatory commissions of such states and the District of Columbia and the FERC.

1.42A.01 Subregional RTEP Project.

"Subregional RTEP Project" shall mean a transmission expansion or enhancement rated below 230 kV which is requiredfor compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.

1.42A.02 Supplemental Project.

"Supplemental Project" shall mean a Regional RTEP Project(s) or Subregional RTEP Project(s), which is not required for compliance with the following PJM criteria: System reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.

1.42B Synchronized Reserve Zone.

"Synchronized Reserve Zone" shall mean any of those geographic areas consisting of a combination of one or more of the Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirement for, Synchronized Reserve service.

1.43 System.

"System" shall mean the interconnected electric supply system of a Member and its interconnected subsidiaries exclusive of facilities which it may own or control outside of the PJM Region. Each Member may include in its system the electric supply systems of any party or parties other than Members which are within the PJM Region, provided its interconnection agreements with such other party or parties do not conflict with such inclusion.

1.43A Third Party Request.

"Third Party Request" shall mean any request or demand by any entity upon an Authorized Person or an Authorized Commission for release or disclosure of confidential information provided to the Authorized Person or Authorized Commission by the Office of the Interconnection or PJM Market Monitor. A Third Party Request shall include, but shall not be limited to, any subpoena, discovery request, or other request for confidential information made by any: (i) federal, state, or local governmental subdivision, department, official, agency or court, or (ii) arbitration panel, business, company, entity or individual.

1.44 Transmission Facilities.

"Transmission Facilities" shall mean facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERC's Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the transmission system of the PJM Region and integrated into the planning and operation of such to serve all of the power and transmission customers within such region.

1.45 Transmission Owner.

"Transmission Owner" shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

1.46 [Reserved.]

1.3 Definitions.

1.3.1 Acceleration Request.

"Acceleration Request" shall mean a request pursuant to section 1.9.4A of this Schedule to accelerate or reschedule a transmission outage scheduled pursuant to sections 1.9.2 or 1.9.4.

1.3.1A Auction Revenue Rights.

"Auction Revenue Rights" or "ARRs" shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Section 7.4 of this Schedule.

1.3.1B Auction Revenue Rights Credits.

"Auction Revenue Rights Credits" shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Section 7.4.3 of this Schedule.

1.3.1B.01 Batch Load Demand Resource.

"Batch Load Demand Resource" shall mean a Demand Resource that has a cyclical production process such that at most times during the process it is consuming energy, but at consistent regular intervals, ordinarily for periods of less than ten minutes, it reduces its consumption of energy for its production processes to minimal or zero megawatts.

1.3.1B.02 Congestion Price.

"Congestion Price" shall mean the congestion component of the Locational Marginal Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.1B.03 Curtailment Service Provider.

"Curtailment Service Provider" or "CSP" shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market by causing a reduction in demand.

1.3.1B.04 Day-ahead Congestion Price.

"Day-ahead Congestion Price" shall mean the Congestion Price resulting from the Day-ahead Energy Market.

1.3.1C Day-ahead Energy Market.

"Day-ahead Energy Market" shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Section 1.10 of this Schedule.

1.3.1C.01 Day-ahead Loss Price.

"Day-ahead Loss Price" shall mean the Loss Price resulting from the Day-ahead Energy Market.

1.3.1D Day-ahead Prices.

"Day-ahead Prices" shall mean the Locational Marginal Prices resulting from the Day-ahead Energy Market.

1.3.1D.01 Day-ahead Scheduling Reserves.

"Day-ahead Scheduling Reserves" shall mean thirty-minute reserves as defined by the Reliability First Corporation and SERC.

1.3.1D.02 Day-ahead Scheduling Reserves Requirement.

"Day-ahead Scheduling Reserves Requirement" shall mean the thirty-minute reserve requirement for the PJM Region established consistent with Reliability First Corporation and SERC reliability standards, or those of any additional and/or successor regional reliability organization(s) that are responsible for establishing reliability requirements for the PJM Region, plus any additional thirty-minute reserves scheduled in response to an RTO-wide Hot or Cold Weather Alert or other reasons for conservative operations.

1.3.1D.03 Day-ahead Scheduling Reserves Resources.

"Day-ahead Scheduling Reserves Resources" shall mean synchronized and non-synchronized generation resources and Demand Resources electrically located within the PJM Region that are capable of providing Day-ahead Scheduling Reserves.

1.3.1D.04 Day-ahead Scheduling Reserves Market.

"Day-ahead Scheduling Reserves Market" shall mean the schedule of commitments for the purchase or sale of Day-ahead Scheduling Reserves developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Section 1.10 of this Schedule.

1.3.1D.05 Day-ahead System Energy Price.

"Day-ahead System Energy Price" shall mean the System Energy Price resulting from the Day-ahead Energy Market.

1.3.1E Decrement Bid.

"Decrement Bid" shall mean a bid to purchase energy at a specified location in the Day-ahead Energy Market. An accepted Decrement Bid results in scheduled load at the specified location in the Day-ahead Energy Market.

1.31E.01 Demand Resource.

"Demand Resource" shall mean a resource with the capability to provide a reduction in demand.

1.3.1F Dispatch Rate.

"Dispatch Rate" shall mean the control signal, expressed in dollars per megawatt-hour, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by the Office of the Interconnection in accordance with the Offer Data.

1.3.1G Energy Storage Resource.

"Energy Storage Resource" shall mean flywheel or battery storage facility solely used for short term storage and injection of energy at a later time to participate in the PJM energy and/or Ancilliary Services markets as a Market Seller.

1.3.2 Equivalent Load.

"Equivalent Load" shall mean the sum of a Market Participant's net system requirements to serve its customer load in the PJM Region, if any, plus its net bilateral transactions.

1.3.2A Economic Load Response Participant.

"Economic Load Response Participant" shall mean a Member or Special Member that qualifies under Section 1.5A of this Schedule to participate in the PJM Interchange Energy Market through reductions in demand.

1.3.2A.01 Economic Minimum.

"Economic Minimum" shall mean the lowest incremental MW output level a unit can achieve while following economic dispatch.

1.3.2B Energy Market Opportunity Cost.

"Energy Market Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of available run hours

due to limitations imposed on the unit by Applicable Laws and Regulations (as defined in PJM Tariff), and (b) the forecasted future hourly Locational Marginal Price at which the generating unit could run while not violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Schedule 2 of the Operating Agreement.

1.3.3 External Market Buyer.

"External Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for consumption by end-users outside the PJM Region, or for load in the PJM Region that is not served by Network Transmission Service.

1.3.4 External Resource.

"External Resource" shall mean a generation resource located outside the metered boundaries of the PJM Region.

1.3.5 Financial Transmission Right.

"Financial Transmission Right" or "FTR" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2 of this Schedule.

1.3.5A Financial Transmission Right Obligation.

"Financial Transmission Right Obligation" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2(b) of this Schedule.

1.3.5B Financial Transmission Right Option.

"Financial Transmission Right Option" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2(c) of this Schedule.

1.3.6 Generating Market Buyer.

"Generating Market Buyer" shall mean an Internal Market Buyer that is a Load Serving Entity that owns or has contractual rights to the output of generation resources capable of serving the Market Buyer's load in the PJM Region, or of selling energy or related services in the PJM Interchange Energy Market or elsewhere.

1.3.7 Generator Forced Outage.

"Generator Forced Outage" shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an Emergency or threatened

Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the PJM Manuals. A reduction in output or removal from service of a generating unit in response to changes in market conditions shall not constitute a Generator Forced Outage.

1.3.8 Generator Maintenance Outage.

"Generator Maintenance Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform necessary repairs on specific components of the facility, if removal of the facility meets the guidelines specified in the PJM Manuals.

1.3.9 Generator Planned Outage.

"Generator Planned Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the Office of the Interconnection in accordance with the PJM Manuals.

1.3.9A Increment Bid.

"Increment Bid" shall mean an offer to sell energy at a specified location in the Day-ahead Energy Market. An accepted Increment Bid results in scheduled generation at the specified location in the Day-ahead Energy Market.

1.3.9B Interface Pricing Point.

"Interface Pricing Point" shall have the meaning specified in section 2.6A.

1.3.10 Internal Market Buyer.

"Internal Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for ultimate consumption by end-users inside the PJM Region that are served by Network Transmission Service.

1.3.11 Inadvertent Interchange.

"Inadvertent Interchange" shall mean the difference between net actual energy flow and net scheduled energy flow into or out of the individual Control Areas operated by PJM.

1.3.11.01 Load Management.

"Load Management" shall mean either a Demand Resource ("DR") or an Interruptible Load for Reliability ("ILR") resource, both as defined in the Reliability Assurance Agreement.

1.3.11A Load Reduction Event.

"Load Reduction Event" shall mean a reduction in demand by a Member or Special Member for the purpose of participating in the PJM Interchange Energy Market.

1.3.11B Loss Price.

"Loss Price" shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.12 Market Operations Center.

"Market Operations Center" shall mean the equipment, facilities and personnel used by or on behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

1.3.12A Maximum Emergency.

"Maximum Emergency" shall mean the designation of all or part of the output of a generating unit for which the designated output levels may require extraordinary procedures and therefore are available to the Office of the Interconnection only when the Office of the Interconnection declares a Maximum Generation Emergency and requests generation designated as Maximum Emergency to run. The Office of the Interconnection shall post on the PJM website the aggregate amount of megawatts that are classified as Maximum Emergency.

1.3.13 Maximum Generation Emergency.

"Maximum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection to address either a generation or transmission emergency in which the Office of the Interconnection anticipates requesting one or more Generation Capacity Resources, or Non-Retail Behind The Meter Generation resources to operate at its maximum net or gross electrical power output, subject to the equipment stress limits for such Generation Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

1.3.14 Minimum Generation Emergency.

"Minimum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

1.3.14A NERC Interchange Distribution Calculator.

"NERC Interchange Distribution Calculator" shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

1.3.14B Net Benefits Test.

"Net Benefits Test" shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Section 3.3A.4 of this Schedule.

1.3.15 Network Resource.

"Network Resource" shall have the meaning specified in the PJM Tariff.

1.3.16 Network Service User.

"Network Service User" shall mean an entity using Network Transmission Service.

1.3.17 Network Transmission Service.

"Network Transmission Service" shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part III of the PJM Tariff, or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

1.3.17A Non-Regulatory Opportunity Cost.

"Non-Regulatory Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, (ii) a fuel supply limitation, for up to one year, resulting from an event of force majeure; and, (b) the forecasted future hourly Locational Marginal Price at which the generating unit could run while not violating such limitations. Non-Regulatory Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same period of time in which the unit is bound by the referenced restrictions, and is reflected in the rules set forth in PJM Manual 15. Non-Regulatory Opportunity Costs shall be limited to those resources which are specifically delineated in Schedule 2 of the Operating Agreement.

1.3.17B Non-Synchronized Reserve.

"Non-Synchronized Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

1.3.17C Non-Synchronized Reserve Event.

"Non-Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources and/or Demand Resources able, assigned or self-scheduled, to provide Non-Synchronized Reserve within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-schedule Non-Synchronized Reserve capability.

1.3.17DB Non-Variable Loads.

"Non-Variable Loads" shall have the meaning specified in section 1.5A.6 of this Schedule.

1.3.18 Normal Maximum Generation.

"Normal Maximum Generation" shall mean the highest output level of a generating resource under normal operating conditions.

1.3.19 Normal Minimum Generation.

"Normal Minimum Generation" shall mean the lowest output level of a generating resource under normal operating conditions.

1.3.20 Offer Data.

"Offer Data" shall mean the scheduling, operations planning, dispatch, new resource, and other data and information necessary to schedule and dispatch generation resources and Demand Resource(s) for the provision of energy and other services and the maintenance of the reliability and security of the transmission system in the PJM Region, and specified for submission to the PJM Interchange Energy Market for such purposes by the Office of the Interconnection.

1.3.21 Office of the Interconnection Control Center.

"Office of the Interconnection Control Center" shall mean the equipment, facilities and personnel used by the Office of the Interconnection to coordinate and direct the operation of the PJM Region and to administer the PJM Interchange Energy Market, including facilities and equipment used to communicate and coordinate with the Market Participants in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

1.3.21A On-Site Generators.

"On-Site Generators" shall mean generation facilities (including Behind The Meter Generation) that (i) are not Capacity Resources, (ii) are not injecting into the grid, (iii) are either synchronized or non-synchronized to the Transmission System, and (iv) can be used to reduce demand for the purpose of participating in the PJM Interchange Energy Market.

1.3.22 Operating Day.

"Operating Day" shall mean the daily 24 hour period beginning at midnight for which transactions on the PJM Interchange Energy Market are scheduled.

1.3.23 Operating Margin.

"Operating Margin" shall mean the incremental adjustments, measured in megawatts, required in PJM Region operations in order to accommodate, on a first contingency basis, an operating contingency in the PJM Region resulting from operations in an interconnected Control Area. Such adjustments may result in constraints causing Transmission Congestion Charges, or may result in Ancillary Services charges pursuant to the PJM Tariff.

1.3.24 Operating Margin Customer.

"Operating Margin Customer" shall mean a Control Area purchasing Operating Margin pursuant to an agreement between such other Control Area and the LLC.

1.3.25 PJM Interchange.

"PJM Interchange" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load exceeds, or is exceeded by, the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup; or (c) the hourly scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the hourly net metered output of any other Market Seller; or (e) the hourly scheduled deliveries of Spot Market Energy to an External Market Buyer; or (f) the hourly scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

1.3.26 PJM Interchange Export.

"PJM Interchange Export" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load is exceeded by the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup sales; or (c) the hourly scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the hourly net metered output of any other Market Seller.

1.3.27 PJM Interchange Import.

"PJM Interchange Import" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load exceeds the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup purchases; or (c) the hourly scheduled deliveries of

Spot Market Energy to an External Market Buyer; or (d) the hourly scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

1.3.28 PJM Open Access Same-time Information System.

"PJM Open Access Same-time Information System" shall mean the electronic communication system for the collection and dissemination of information about transmission services in the PJM Region, established and operated by the Office of the Interconnection in accordance with FERC standards and requirements.

1.3.28A Planning Period Quarter.

"Planning Period Quarter" shall mean any of the following three month periods in the Planning Period: June, July and August; September, October and November; December, January and February; or March, April and May.

1.3.28B Planning Period Balance.

"Planning Period Balance" shall mean the entire period of time remaining in the Planning Period following the month that a monthly auction is conducted.

1.3.29 Point-to-Point Transmission Service.

"Point-to-Point Transmission Service" shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part II of the PJM Tariff.

1.3.29A PRD Curve

PRD Curve shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29B PRD Provider

PRD Provider shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29C PRD Reservation Price

PRD Reservation Price shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29D PRD Substation

PRD Substation shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29E Price Responsive Demand

Price Responsive Demand shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29F Primary Reserve

"Primary Reserve" "Primary Reserve" shall mean the total reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes of a request from the Office of the Interconnection dispatcher, and is comprised of both Synchronized Reserve and Non-Synchronized Reserve.

1.3.30 Ramping Capability.

"Ramping Capability" shall mean the sustained rate of change of generator output, in megawatts per minute.

1.3.30.01 Real-time Congestion Price.

"Real-time Congestion Price" shall mean the Congestion Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30.02 Real-time Loss Price.

"Real-time Loss Price" shall mean the Loss Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30A Real-time Prices.

"Real-time Prices" shall mean the Locational Marginal Prices resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30B Real-time Energy Market.

"Real-time Energy Market" shall mean the purchase or sale of energy and payment of Transmission Congestion Charges for quantity deviations from the Day-ahead Energy Market in the Operating Day.

1.3.30B.01 Real-time System Energy Price.

"Real-time System Energy Price" shall mean the System Energy Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.31 Regulation.

"Regulation" shall mean the capability of a specific generation resource or Demand Resource with appropriate telecommunications, control and response capability to increase or decrease its output or adjust load in response to a regulating control signal, in accordance with the specifications in the PJM Manuals.

1.3.31.001 Reserve Penalty Factor.

"Reserve Penalty Factor" shall mean the cost, in $/MWh, associated with being unable to meet a specific reserve requirement in a Reserve Zone. A Reserve Penalty Factor will be defined for each reserve requirement in a Reserve Zone.

1.3.31.01 Residual Auction Revenue Rights.

"Residual Auction Revenue Rights" shall mean incremental stage 1 Auction Revenue Rights created within a Planning Period by an increase in transmission system capability or a change in any other relevant factor that was not modeled pursuant to section 7.5 of Schedule 1 of this Agreement in compliance with section 7.4.2(h) of Schedule 1 of this Agreement, and, if modeled, would have increased the amount of stage 1 Auction Revenue Rights allocated pursuant to section 7.4.2 of Schedule 1 of this Agreement; provided that, the foregoing notwithstanding, Residual Auction Revenue Rights shall exclude: 1) Incremental Auction Revenue Rights allocated pursuant to Part VI of the Tariff; and 2) Auction Revenue Rights allocated to entities that are assigned cost responsibility pursuant to Schedule 6 of this Agreement for transmission upgrades that create such rights.

1.3.31.02 Special Member.

"Special Member" shall mean an entity that satisfies the requirements of Section 1.5A.02 of this Schedule or the special membership provisions established under the Emergency Load Response Program.

1.3.31A [Reserved.]

1.3.31B [Reserved.]

1.3.32 Spot Market Backup.

"Spot Market Backup" shall mean the purchase of energy from, or the delivery of energy to, the PJM Interchange Energy Market in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason.

1.3.33 Spot Market Energy.

"Spot Market Energy" shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at System Energy Prices determined as specified in Section 2 of this Schedule.

1.3.33A State Estimator.

"State Estimator" shall mean the computer model of power flows specified in Section 2.3 of this Schedule.

1.3.33B Station Power.

"Station Power" shall mean energy used for operating the electric equipment on the site of a generation facility located in the PJM Region or for the heating, lighting, air-conditioning and office equipment needs of buildings on the site of such a generation facility that are used in the operation, maintenance, or repair of the facility. Station Power does not include any energy (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility; (iii) used for compressors at a compressed air energy storage facility; (iv) used for charging an Energy Storage Resource; or (v) used in association with restoration or black start service.

1.3.33B.01 Synchronized Reserve.

"Synchronized Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes from the request of the Office of the Interconnection dispatcher, and is provided by equipment that is electrically synchronized to the Transmission System.

1.3.33B.02 Synchronized Reserve Event.

"Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources and/or Demand Resources able, assigned or self-scheduled to provide Synchronized Reserve, within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-scheduled Synchronized Reserve capability.

1.3.33B.03 System Energy Price.

"System Energy Price" shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.33C Target Allocation.

"Target Allocation" shall mean the allocation of Transmission Congestion Credits as set forth in Section 5.2.3 of this Schedule or the allocation of Auction Revenue Rights Credits as set forth in Section 7.4.3 of this Schedule.

1.3.34 Transmission Congestion Charge.

"Transmission Congestion Charge" shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses in accordance with Section 9.3, which shall be calculated and allocated as specified in Section 5.1 of this Schedule.

1.3.35 Transmission Congestion Credit.

"Transmission Congestion Credit" shall mean the allocated share of total Transmission Congestion Charges credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section 5.2 of this Schedule.

1.3.36 Transmission Customer.

"Transmission Customer" shall mean an entity using Point-to-Point Transmission Service.

1.3.37 Transmission Forced Outage.

"Transmission Forced Outage" shall mean an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the PJM Manuals. A removal from service of a transmission facility at the request of the Office of the Interconnection to improve transmission capability shall not constitute a Forced Transmission Outage.

1.3.37A Transmission Loading Relief.

"Transmission Loading Relief" shall mean NERC's procedures for preventing operating security limit violations, as implemented by PJM as the security coordinator responsible for maintaining transmission security for the PJM Region.

1.3.37B Transmission Loading Relief Customer.

"Transmission Loading Relief Customer" shall mean an entity that, in accordance with Section 1.10.6A, has elected to pay Transmission Congestion Charges during Transmission Loading Relief in order to continue energy schedules over contract paths outside the PJM Region that are increasing the cost of energy in the PJM Region.

1.3.37C Transmission Loss Charge.

"Transmission Loss Charge" shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Section 5 of this Schedule.

1.3.38 Transmission Planned Outage.

"Transmission Planned Outage" shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in this Agreement or the PJM Manuals.

1.3.38A Variable Loads.

“Variable Loads” shall have the meaning specified in section 1.5A.6 of this Schedule.

1.3.39 Zonal Base Load.

“Zonal Base Load” shall mean the lowest daily zonal peak load from the twelve month period ending October 21 of the calendar year immediately preceding the calendar year in which an annual Auction Revenue Right allocation is conducted, increased by the projected load growth rate for the relevant Zone.

1.7 General.

1.7.1 Market Sellers.

Only Market Sellers shall be eligible to submit offers to the Office of the Interconnection for the sale of electric energy or related services in the PJM Interchange Energy Market. Market Sellers shall comply with the prices, terms, and operating characteristics of all Offer Data submitted to and accepted by the PJM Interchange Energy Market.

1.7.2 Market Buyers.

Only Market Buyers shall be eligible to purchase energy or related services in the PJM Interchange Energy Market. Market Buyers shall comply with all requirements for making purchases from the PJM Interchange Energy Market.

1.7.2A Economic Load Response Participants.

Only Economic Load Response Participants shall be eligible to participate in the Real-time Energy Market and the Day-ahead Energy Market by submitting offers to the Office of the Interconnection to reduce demand.

1.7.3 Agents.

A Market Participant may participate in the PJM Interchange Energy Market through an agent, provided that the Market Participant informs the Office of the Interconnection in advance in writing of the appointment of such agent. A Market Participant participating in the PJM Interchange Energy Market through an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the PJM Interchange Energy Market, and shall ensure that any such agent complies with the requirements of this Agreement.

1.7.4 General Obligations of the Market Participants.

(a) In performing its obligations to the Office of the Interconnection hereunder, each Market Participant shall at all times (i) follow Good Utility Practice, (ii) comply with all applicable laws and regulations, (iii) comply with the applicable principles, guidelines, standards and requirements of FERC, NERC and Applicable Regional Reliability Councils, (iv) comply with the procedures established for operation of the PJM Interchange Energy Market and PJM Region and (v) cooperate with the Office of the Interconnection as necessary for the operation of the PJM Region in a safe, reliable manner consistent with Good Utility Practice.

(b) Market Participants shall undertake all operations in or affecting the PJM Interchange Energy Market and the PJM Region including but not limited to compliance with all Emergency procedures, in accordance with the power and authority of the Office of the Interconnection with

respect to the operation of the PJM Interchange Energy Market and the PJM Region as established in this Agreement, and as specified in the Schedules to this Agreement and the PJM Manuals. Failure to comply with the foregoing operational requirements shall subject a Market Participant to such reasonable charges or other remedies or sanctions for non-compliance as may be established by the PJM Board, including legal or regulatory proceedings as authorized by the PJM Board to enforce the obligations of this Agreement.

(c) The Office of the Interconnection may establish such committees with a representative of each Market Participant, and the Market Participants agree to provide appropriately qualified personnel for such committees, as may be necessary for the Office of the Interconnection and PJMSettlement to perform its obligations hereunder.

(d) All Market Participants shall provide to the Office of the Interconnection the scheduling and other information specified in the Schedules to this Agreement, and such other information as the Office of the Interconnection may reasonably require for the reliable and efficient operation of the PJM Region and PJM Interchange Energy Market, and for compliance with applicable regulatory requirements for posting market and related information. Such information shall be provided as much in advance as possible, but in no event later than the deadlines established by the Schedules to this Agreement, or by the Office of the Interconnection in conformance with such Schedules. Such information shall include, but not be limited to, maintenance and other anticipated outages of generation or transmission facilities, scheduling and related information on bilateral transactions and self-scheduled resources, and implementation of active load management, interruption of load, Price Responsive Demand, and other load reduction measures. The Office of the Interconnection shall abide by appropriate requirements for the non-disclosure and protection of any confidential or proprietary information given to the Office of the Interconnection by a Market Participant. Each Market Participant shall maintain or cause to be maintained compatible information and communications systems, as specified by the Office of the Interconnection, required to transmit scheduling, dispatch, or other time-sensitive information to the Office of the Interconnection in a timely manner.

(e) Subject to the requirements for Economic Load Response participants in section 1.5A above, each Market Participant shall install and operate, or shall otherwise arrange for, metering and related equipment capable of recording and transmitting all voice and data communications reasonably necessary for the Office of the Interconnection and PJMSettlement to perform the services specified in this Agreement. A Market Participant that elects to be separately billed for its PJM Interchange shall, to the extent necessary, be individually metered in accordance with Section 14 of this Agreement, or shall agree upon an allocation of PJM Interchange between it and the Market Participant through whose meters the unmetered Market Participant's PJM Interchange is delivered. The Office of the Interconnection shall be notified of the allocation by the foregoing Market Participants.

(f) Each Market Participant shall operate, or shall cause to be operated, any generating resources owned or controlled by such Market Participant that are within the PJM Region or otherwise supplying energy to or through the PJM Region in a manner that is consistent with the standards, requirements or directions of the Office of the Interconnection and that will permit the Office of the Interconnection to perform its obligations under this Agreement; provided,

however, no Market Participant shall be required to take any action that is inconsistent with Good Utility Practice or applicable law.

(g) Each Market Participant shall follow the directions of the Office of the Interconnection to take actions to prevent, manage, alleviate or end an Emergency in a manner consistent with this Agreement and the procedures of the PJM Region as specified in the PJM Manuals.

(h) Each Market Participant shall obtain and maintain all permits, licenses or approvals required for the Market Participant to participate in the PJM Interchange Energy Market in the manner contemplated by this Agreement.

(i) Consistent with Section 36.1.1 of the PJM Tariff, to the extent its generating facility is dispatchable, a Market Participant shall submit an Economic Minimum in the Real-time Energy Market that is no greater than the higher of its physical operating minimum or its Capacity Interconnection Rights, as that term is defined in the PJM Tariff, associated with such generating facility under its Interconnection Service Agreement under Attachment O of the PJM Tariff or a wholesale market participation agreement.

1.7.5 Market Operations Center.

Each Market Participant shall maintain a Market Operations Center, or shall make appropriate arrangements for the performance of such services on its behalf. A Market Operations Center shall meet the performance, equipment, communications, staffing and training standards and requirements specified in this Agreement for the scheduling and completion of transactions in the PJM Interchange Energy Market and the maintenance of the reliable operation of the PJM Region, and shall be sufficient to enable (i) a Market Seller or an Economic Load Response Participant to perform all terms and conditions of its offers to the PJM Interchange Energy Market, and (ii) a Market Buyer or an Economic Load Response Participant to conform to the requirements for purchasing from the PJM Interchange Energy Market.

1.7.6 Scheduling and Dispatching.

(a) The Office of the Interconnection shall schedule and dispatch in real-time generation resources and/or Demand Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Sellers, continuing until sufficient generation resources and/or Demand Resources are dispatched to serve the PJM Interchange Energy Market energy purchase requirements under normal system conditions of the Market Buyers (taking into account any reductions to such requirements in accordance with PRD Curves properly submitted by PRD Providers), as well as the requirements of the PJM Region for ancillary services provided by generation resources and/or Demand Resources, in accordance with this Agreement. Such scheduling and dispatch shall recognize transmission constraints on coordinated flowgates external to the Transmission System in accordance with Appendix A to the Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38) and on other such flowgates that are coordinated in accordance with agreements between the LLC

and other entities. Scheduling and dispatch shall be conducted in accordance with this Agreement.

(b) The Office of the Interconnection shall undertake to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the PJM Interchange Energy Market, and any relevant procedures of another Control Area, or any tariff (including the PJM Tariff). Upon determining that any such conflict or incompatibility exists, the Office of the Interconnection shall propose tariff or procedural changes, and undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

(c) To protect its generation or distribution facilities, or local Transmission Facilities not under the monitoring responsibility and dispatch control of the Office of the Interconnection, an entity may request that the Office of the Interconnection schedule and dispatch generation or reductions in demand to meet a limit on Transmission Facilities different from that which the Office of the Interconnection has determined to be required for reliable operation of the Transmission System. To the extent consistent with its other obligations under this Agreement, the Office of the Interconnection shall schedule and dispatch generation and reductions in demand in accordance with such request. An entity that makes a request pursuant to this section 1.7.6(c) shall be responsible for all generation and other costs resulting from its request that would not have been incurred by operating the Transmission System and scheduling and dispatching generation in the manner that the Office of the Interconnection otherwise has determined to be required for reliable operation of the Transmission System.

1.7.7 Pricing.

The price paid for energy bought and sold in the PJM Interchange Energy Market and for demand reductions will reflect the hourly Locational Marginal Price at each load and generation bus, determined by the Office of the Interconnection in accordance with this Agreement. Transmission Congestion Charges and Transmission Loss Charges, which shall be determined by differences in Congestion Prices and Loss Prices in an hour, shall be calculated by the Office of the Interconnection, and collected by PJMSettlement, and the revenues therefrom shall be disbursed by PJMSettlement in accordance with this Schedule.

1.7.8 Generating Market Buyer Resources.

A Generating Market Buyer may elect to self-schedule its generation resources up to that Generating Market Buyer's Equivalent Load, in accordance with and subject to the procedures specified in this Schedule, and the accounting and billing requirements specified in Section 3 to this Schedule. PJMSettlement shall not be a contracting party with respect to such self-scheduled or self-supplied transactions.

1.7.9 Delivery to an External Market Buyer.

A purchase of Spot Market Energy by an External Market Buyer shall be delivered to a bus or buses at the electrical boundaries of the PJM Region specified by the Office of the Interconnection, or to load in such area that is not served by Network Transmission Service,

using Point-to-Point Transmission Service paid for by the External Market Buyer. Further delivery of such energy shall be the responsibility of the External Market Buyer.

1.7.10 Other Transactions.

(a) Bilateral Transactions.

(i) In addition to transactions in the PJM Interchange Energy Market, Market Participants may enter into bilateral contracts for the purchase or sale of electric energy to or from each other or any other entity, subject to the obligations of Market Participants to make Generation Capacity Resources available for dispatch by the Office of the Interconnection. Such bilateral contracts shall be for the physical transfer of energy to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its eSchedules and Enhanced Energy Scheduler tools.

(ii) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of energy to a Market Participant inside the PJM Region, title to the energy that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and the further transmission of the energy or further sale of the energy into the PJM Interchange Energy Market shall be transacted by the buyer under the bilateral contract. With respect to all bilateral contracts for the physical transfer of energy to an entity outside the PJM Region, title to the energy shall pass to the buyer at the border of the PJM Region and shall be delivered to the border using transmission service. In no event shall the purchase and sale of energy between Market Participants under a bilateral contract constitute a transaction in the PJM Interchange Energy Market or be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

(iii) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of energy reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the megawatt hours of such reported transactions to amounts reflecting the expected load and other physical delivery obligations of the buyer under the bilateral contract.

(iv) All payments and related charges for the energy associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. 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 a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

(v) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any Spot Market Backup used to meet the bilateral contract seller's obligation to deliver energy under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new eSchedules or Enhanced Energy Scheduler reporting by the Market Participant and (ii) terminate all of the Market Participant's eSchedules and Enhanced Energy Schedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the eSchedules and Enhanced Energy Schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection. PJMSettlement shall assign its claims against a seller with respect to a seller's nonpayment for Spot Market Backup to a buyer the extent that the buyer has made an indemnification payment to PJMSettlement with respect to the seller's nonpayment.

(vi) Bilateral contracts that do not contemplate the physical transfer of energy to or from a Market Participant are not subject to this Schedule, shall not be reported to and coordinated with the Office of the Interconnection, and shall not in any way constitute a transaction in the PJM Interchange Energy Market.

(b) Market Participants shall have Spot Market Backup with respect to all bilateral transactions that contemplate the physical transfer of energy to or from a Market Participant, that are not dynamically scheduled pursuant to Section 1.12 and that are curtailed or interrupted for any reason (except for curtailments or interruptions through active load management for load located within the PJM Region).

(c) To the extent the Office of the Interconnection dispatches a Generating Market Buyer's generation resources, such Generating Market Buyer may elect to net the output of such resources against its hourly Equivalent Load. Such a Generating Market Buyer shall be deemed a buyer from the PJM Interchange Energy Market to the extent of its PJM Interchange Imports, and shall be deemed a seller to the PJM Interchange Energy Market to the extent of its PJM Interchange Exports.

(d) A Market Seller may self-supply Station Power for its generation facility in accordance with the following provisions:

(i) A Market Seller may self-supply Station Power for its generation facility during any month (1) when the net output of such facility is positive, or (2) when the net output of such facility is negative and the Market Seller during the same month has available at other of its generation facilities positive net output in an amount at least sufficient to offset fully such negative net output. For purposes of this subsection (d), "net output" of a generation facility during any month means the facility's gross energy output, less the Station Power requirements of such facility, during that month. The determination of a generation facility's or a Market Seller's monthly net output under this subsection (d) will apply only to determine whether the Market Seller self-supplied Station Power during the month and will not affect the price of energy sold or consumed by the Market Seller at any bus during any hour during the month. For each hour when a Market Seller has positive net output and delivers energy into the Transmission System, it will be paid the LMP at its bus for that hour for all of the energy delivered. Conversely, for each hour when a Market Seller has negative net output and has received Station Power from the Transmission System, it will pay the LMP at its bus for that hour for all of the energy consumed.

(ii) Transmission Provider will determine the extent to which each affected Market Seller during the month self-supplied its Station Power requirements or obtained Station Power from third-party providers (including affiliates) and will incorporate that determination in its accounting and billing for the month. In the event that a Market Seller self-supplies Station Power during any month in the manner described in subsection (1) of subsection (d)(i) above, Market Seller will not use, and will not incur any charges for, transmission service. In the event, and to the extent, that a Market Seller self-supplies Station Power during any month in the manner described in subsection (2) of subsection (d)(i) above (hereafter referred to as "remote self-supply of Station Power"), Market Seller shall use and pay for transmission service for the transmission of energy in an amount equal to the facility's negative net output from Market Seller's generation facility(ies) having positive net output. Unless the Market Seller makes other arrangements with Transmission Provider in advance, such transmission service shall be provided under Part II of the PJM Tariff and shall be charged the hourly rate under Schedule 8 of the PJM Tariff for Non-Firm Point-to-Point Transmission Service with an election to pay congestion charges, provided, however, that no reservation shall be necessary for such transmission service and the terms and charges under Schedules 1, 1A, 2 through 6, 9 and 10 of the PJM Tariff shall not apply to such service. The amount of energy that a Market Seller transmits in conjunction with remote self-supply of Station Power will not

be affected by any other sales, purchases, or transmission of capacity or energy by or for such Market Seller under any other provisions of the PJM Tariff.

(iii) A Market Seller may self-supply Station Power from its generation facilities located outside of the PJM Region during any month only if such generation facilities in fact run during such month and Market Seller separately has reserved transmission service and scheduled delivery of the energy from such resource in advance into the PJM Region.

1.7.11 Emergencies.

(a) The Office of the Interconnection, with the assistance of the Members' dispatchers as it may request, shall be responsible for monitoring the operation of the PJM Region, for declaring the existence of an Emergency, and for directing the operations of Market Participants as necessary to manage, alleviate or end an Emergency. The standards, policies and procedures of the Office of the Interconnection for declaring the existence of an Emergency, including but not limited to a Minimum Generation Emergency, and for managing, alleviating or ending an Emergency, shall apply to all Members on a non-discriminatory basis. Actions by the Office of the Interconnection and the Market Participants shall be carried out in accordance with this Agreement, the NERC Operating Policies, Applicable Regional Reliability Council reliability principles and standards, Good Utility Practice, and the PJM Manuals. A declaration that an Emergency exists or is likely to exist by the Office of the Interconnection shall be binding on all Market Participants until the Office of the Interconnection announces that the actual or threatened Emergency no longer exists. Consistent with existing contracts, all Market Participants shall comply with all directions from the Office of the Interconnection for the purpose of managing, alleviating or ending an Emergency. The Market Participants shall authorize the Office of the Interconnection and PJMSettlement to purchase or sell energy on their behalf to meet an Emergency, and otherwise to implement agreements with other Control Areas interconnected with the PJM Region for the mutual provision of service to meet an Emergency, in accordance with this Agreement.

(b) To the extent load must be shed to alleviate an Emergency in a Control Zone, the Office of the Interconnection shall, to the maximum extent practicable, direct the shedding of load within such Control Zone. The Office of the Interconnection may shed load in one Control Zone to alleviate an Emergency in another Control Zone under its control only as necessary after having first shed load to the maximum extent practicable in the Control Zone experiencing the Emergency and only to the extent that PJM supports other control areas (not under its control) in those situations where load shedding would be necessary, such as to prevent isolation of facilities within the Eastern Interconnection, to prevent voltage collapse, or to restore system frequency following a system collapse; provided, however, that the Office of the Interconnection may not order a manual load dump in a Control Zone solely to address capacity deficiencies in another Control Zone. This subsection shall be implemented consistent with North American Electric Reliability Council and applicable reliability council standards.

1.7.12 Fees and Charges.

Each Market Participant, except for Special Members, shall pay all fees and charges of the Office of the Interconnection for operation of the PJM Interchange Energy Market as determined by and allocated to the Market Participant by the Office of the Interconnection in accordance with Schedule 3.

1.7.13 Relationship to the PJM Region.

The PJM Interchange Energy Market operates within and subject to the requirements for the operation of the PJM Region.

1.7.14 PJM Manuals.

The Office of the Interconnection shall be responsible for maintaining, updating, and promulgating the PJM Manuals as they relate to the operation of the PJM Interchange Energy Market. The PJM Manuals, as they relate to the operation of the PJM Interchange Energy Market, shall conform and comply with this Agreement, NERC operating policies, and Applicable Regional Reliability Council reliability principles, guidelines and standards, and shall be designed to facilitate administration of an efficient energy market within industry reliability standards and the physical capabilities of the PJM Region.

1.7.15 Corrective Action.

Consistent with Good Utility Practice, the Office of the Interconnection shall be authorized to direct or coordinate corrective action, whether or not specified in the PJM Manuals, as necessary to alleviate unusual conditions that threaten the integrity or reliability of the PJM Region, or the regional power system.

1.7.16 Recording.

Subject to the requirements of applicable State or federal law, all voice communications with the Office of the Interconnection Control Center may be recorded by the Office of the Interconnection and any Market Participant communicating with the Office of the Interconnection Control Center, and each Market Participant hereby consents to such recording.

1.7.17 Operating Reserves.

(a) The following procedures shall apply to any generation unit subject to the dispatch of the Office of the Interconnection for which construction commenced before July 9, 1996, or any Demand Resource subject to the dispatch of the Office of the Interconnection.

(b) The Office of the Interconnection shall schedule to the Operating Reserve and load-following objectives of the Control Zones of the PJM Region and the PJM Interchange Energy Market in scheduling generation resources and/or Demand Resources pursuant to this Schedule. A table of Operating Reserve objectives for each Control Zone is calculated and published

annually in the PJM Manuals. Reserve levels are probabilistically determined based on the season's historical load forecasting error and forced outage rates.

(c) Nuclear generation resources shall not be eligible for Operating Reserve payments unless: 1) the Office of the Interconnection directs such resources to reduce output, in which case, such units shall be compensated in accordance with section 3.2.3(f) of this Schedule; or 2) the resource submits a request for a risk premium to the Market Monitoring Unit under the procedures specified in Section II.B of Attachment M - Appendix. A nuclear generation resource (i) must submit a risk premium consistent with its agreement under such process, or, (ii) if it has not agreed with the Market Monitoring Unit on an appropriate risk premium, may submit its own determination of an appropriate risk premium to the Office of the Interconnection, subject to acceptance by the Office of the Interconnection, with or without prior approval from the Commission.

(d) PJMSettlement shall be the Counterparty to the purchases and sales of Operating Reserve in the PJM Interchange Energy Market.

1.7.18 Regulation.

(a) Regulation to meet the Regulation objective of each Regulation Zone shall be supplied from generation resources and/or Demand Resources located within the metered electrical boundaries of such Regulation Zone. Generating Market Buyers, and Market Sellers offering Regulation, shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the PJM Manuals.

(b) The Office of the Interconnection shall obtain and maintain for each Regulation Zone an amount of Regulation equal to the Regulation objective for such Regulation Zone as specified in the PJM Manuals.

(c) The Regulation range of a generation unit or Demand Resource shall be at least twice the amount of Regulation assigned as described in the PJM Manuals.

(d) A ~~generation unit~~resource capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced by at least twice the amount of the Regulation provided with consideration of ~~. T~~the ~~amount of~~ Regulation ~~provided by a generation unit shall serve to redefine the Normal Minimum Generation and Normal Maximum Generation energy~~ limits of that ~~generation unit~~resource, ~~in that the amount of Regulation shall be added to the generation unit's Normal Minimum Generation energy limit, and subtracted from its Normal Maximum Generation energy limit~~ as specified in the PJM Manuals.

(e) Qualified Regulation must satisfy the verification tests described in the PJM Manuals.

1.7.19 Ramping.

A generator dispatched by the Office of the Interconnection pursuant to a control signal appropriate to increase or decrease the generator's megawatt output level shall be able to change

output at the ramping rate specified in the Offer Data submitted to the Office of the Interconnection for that generator.

1.7.19A Synchronized Reserve.

(a) Synchronized Reserve shall be supplied from generation resources and/or Demand Resources located within the metered boundaries of the PJM Region. Generating Market Buyers, and Market Sellers offering Synchronized Reserve shall comply with applicable standards and requirements for Synchronized Reserve capability and dispatch specified in the PJM Manuals.

(b) The Office of the Interconnection shall obtain and maintain for each ~~Synchronized~~ Reserve Zone an amount of Primary and Synchronized Reserve equal to the respective Primary and Synchronized Reserve objectives for such ~~Synchronized~~ Reserve Zone, as specified in the PJM Manuals.

(c) The Synchronized Reserve capability of a generation resource and Demand Resource shall be the increase in energy output or load reduction achievable by the generation resource and Demand Resource within a continuous 10-minute period.

(d) A generation unit capable of automatic energy dispatch that also is providing Synchronized Reserve shall have its energy dispatch range reduced by the amount of the Synchronized Reserve provided. The amount of Synchronized Reserve provided by a generation unit shall serve to redefine the Normal Maximum Generation energy limit of that generation unit in that the amount of Synchronized Reserve provided shall be subtracted from its Normal Maximum Generation energy limit.

1.7.19A.01 Non-Synchronized Reserve.

(a) Non-Synchronized Reserve shall be supplied from generation resources and/or Demand Resources located within the metered boundaries of the PJM Region. Generating Market Buyers and Market Sellers offering Non-Synchronized Reserve shall comply with applicable standards and requirements for Non-Synchronized Reserve capability and dispatch specified in the PJM Manuals.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone an amount of Non-Synchronized Reserve such that the sum of the Synchronized Reserve and Non-Synchronized Reserve meets the Primary Reserve objective for such Reserve Zone, as specified in the PJM Manuals.

(c) The Non-Synchronized Reserve capability of a generation resource and Demand Resource shall be the increase in energy output or load reduction achievable by the generation resource and Demand Resource within a continuous 10-minute period provided that the resource is not synchronized to the system at the initiation of the response.

1.7.19B Bilateral Transactions Regarding Regulation, Synchronized Reserve and Day-ahead Scheduling Reserves.

(a) In addition to transactions in the Regulation market, Synchronized Reserve market, and Day-ahead Scheduling Reserves Market, Market Participants may enter into bilateral contracts for the purchase or sale of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from each other or any other entity. Such bilateral contracts shall be for the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its eMarket tools.

(b) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to a Market Participant in the PJM Region, title to the product that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and any further transactions associated with such products or further sale of such Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves in the markets for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves, respectively, shall be transacted by the buyer under the bilateral contract. In no event shall the purchase and sale of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves between Market Participants under a bilateral contract constitute a transaction in PJM's markets for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves, or otherwise construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

(c) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the amounts of such reported transactions to amounts reflecting the expected requirements for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves of the buyer pursuant to such bilateral contracts.

(d) All payments and related charges for the Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection. The LLC, PJM Settlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

(e) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any purchases by the seller under the bilateral contract in the markets for Regulations, Synchronized Reserve, or Day-ahead Scheduling Reserves used to meet the bilateral contract seller's obligation to deliver Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as

determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new eMarket reporting by the Market Participant and (ii) terminate all of the Market Participant's reporting of eMarkets schedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the reported eMarkets schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection.

(f) Market Participants shall purchase Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves from PJM's markets for Regulation, Synchronized Reserve, Day-ahead Scheduling Reserves, in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason, with respect to all bilateral transactions that contemplate the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from a Market Participant.

1.7.20 Communication and Operating Requirements.

(a) Market Participants. Each Market Participant shall have, or shall arrange to have, its transactions in the PJM Interchange Energy Market subject to control by a Market Operations Center, with staffing and communications systems capable of real-time communication with the Office of the Interconnection during normal and Emergency conditions and of control of the Market Participant's relevant load or facilities sufficient to meet the requirements of the Market Participant's transactions with the PJM Interchange Energy Market, including but not limited to the following requirements as applicable.

(b) Market Sellers selling from generation resources and/or Demand Resources within the PJM Region shall: report to the Office of the Interconnection sources of energy and Demand Resources available for operation; supply to the Office of the Interconnection all applicable Offer Data; report to the Office of the Interconnection generation resources that are self-scheduled; with respect to generation resources, report to the Office of the Interconnection bilateral sales transactions to buyers not within the PJM Region; confirm to the Office of the Interconnection bilateral sales to Market Buyers within the PJM Region; respond to the Office of the Interconnection's directives to start, shutdown or change output levels of generation units, or change scheduled voltages or reactive output levels of generation units, or reduce load from Demand Resources; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, generating equipment and Demand Resources are operated with control equipment functioning as specified in the PJM Manuals.

(c) Market Sellers selling from generation resources outside the PJM Region shall: provide to the Office of the Interconnection all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to Office of the Interconnection directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the Market Seller's Control Area.

(d) Market Participants that are Load Serving Entities or purchasing on behalf of Load Serving Entities shall: respond to Office of the Interconnection directives for load management steps; report to the Office of the Interconnection Generation Capacity Resources to satisfy capacity obligations that are available for pool operation; report to the Office of the Interconnection all bilateral purchase transactions; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(e) Market Participants that are not Load Serving Entities or purchasing on behalf of Load Serving Entities shall: provide to the Office of the Interconnection requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the PJM Interchange Energy Market, along with Dispatch Rate levels above which it does not desire to purchase; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(f) Economic Load Response Participants are responsible for maintaining demand reduction information, including the amount and price at which demand may be reduced. The Economic Load Response Participant shall provide this information to the Office of the Interconnection by posting it on the Load Response Program Registration link of the PJM website as required by the PJM Manuals. The Economic Load Response Participant shall notify the Office of the Interconnection of a demand reduction concurrent with, or prior to, the beginning of such demand reduction in accordance with the PJM Manuals. In the event that an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer that would affect a relevant Customer Baseline Load as required by the PJM Manuals.

(g) PRD Providers shall be responsible for ensuring automated reductions to their Price Responsive Demand in response to price in accordance with their PRD Curves submitted to the Office of the Interconnection.

1.10 Scheduling.

1.10.1 General.

(a) The Office of the Interconnection shall administer scheduling processes to implement a Day-ahead Energy Market and a Real-time Energy Market. PJMSettlement shall be the Counterparty to the purchases and sales of energy that clear the Day-ahead Energy Market and the Real-time Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a Generating Market Buyer's self-schedule or self-supply of its generation resources up to that Generating Market Buyer's Equivalent Load.

(b) The Day-ahead Energy Market shall enable Market Participants to purchase and sell energy through the PJM Interchange Energy Market at Day-ahead Prices and enable Transmission Customers to reserve transmission service with Transmission Congestion Charges and Transmission Loss Charges based on locational differences in Day-ahead Prices. Up-To Congestion transactions submitted in the Day-ahead Energy Market shall not require transmission service and Transmission Customers shall not reserve transmission service for such transactions. Market Participants whose purchases and sales, and Transmission Customers whose transmission uses are scheduled in the Day-ahead Energy Market, shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, at the applicable Day-ahead Prices for the amounts scheduled.

(c) In the Real-time Energy Market, Market Participants that deviate from the amounts of energy purchases or sales, or Transmission Customers that deviate from the transmission uses, scheduled in the Day-ahead Energy Market shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling shall be conducted as specified below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such Emergency, in

accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM Manuals.

1.10.1A Day-ahead Energy Market Scheduling.

The following actions shall occur not later than 12:00 noon on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the Office of the Interconnection in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Schedule.

(a) Each Market Participant may submit to the Office of the Interconnection specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the PJM Manuals. Each Market Buyer shall inform the Office of the Interconnection of the prices, if any, at which it desires not to include its load in the Day-ahead Energy Market rather than pay the Day-ahead Price. PRD Providers that have committed Price Responsive Demand in accordance with the Reliability Assurance Agreement shall submit to the Office of the Interconnection, in accordance with procedures specified in the PJM Manuals, any desired updates to their previously submitted PRD Curves, provided that such updates are consistent with their Price Responsive Demand commitments, and provided further that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue may only submit PRD Curves for the Real-time Energy Market. Price Responsive Demand that has been committed in accordance with the Reliability Assurance Agreement shall be presumed available for the next Operating Day in accordance with the most recently submitted PRD Curve unless the PRD Curve is updated to indicate otherwise. PRD Providers may also submit PRD Curves for any Price Responsive Demand that is not committed in accordance with the Reliability Assurance Agreement; provided that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue may only submit PRD Curves for the Real-time Energy Market. All PRD Curves shall be on a PRD Substation basis, and shall specify the maximum time period required to implement load reductions.

(b) Each Generating Market Buyer shall submit to the Office of the Interconnection: (i) hourly schedules for resource increments, including hydropower units, self-scheduled by the Market Buyer to meet its Equivalent Load; and (ii) the Dispatch Rate at which each such self-scheduled resource will disconnect or reduce output, or confirmation of the Market Buyer's intent not to reduce output.

(c) All Market Participants shall submit to the Office of the Interconnection schedules for any bilateral transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection whether the transaction is to be included in the Day-ahead Energy Market. Any Market Participant that elects to include a bilateral transaction in the Day-ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the PJM Manuals), if any, at which it will be wholly or partially curtailed rather than pay Transmission Congestion Charges. The foregoing price specification shall apply to the price difference between the specified bilateral transaction source and sink points in the day-ahead scheduling process only. Any Market Participant that

elects not to include its bilateral transaction in the Day-ahead Energy Market shall inform the Office of the Interconnection if the parties to the transaction are not willing to incur Transmission Congestion Charges in the Real-time Energy Market in order to complete any such scheduled bilateral transaction. Scheduling of bilateral transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

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

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

iii) In addition to the foregoing schedules for bilateral transactions, Market Participants shall submit confirmations of each scheduled bilateral transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(d) Market Sellers wishing to sell into the Day-ahead Energy Market shall submit offers for the supply of energy (including energy from hydropower units), demand reductions, Regulation, Operating Reserves or other services for the following Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Attachment DD of the PJM Tariff, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. Any offer not designated as a Maximum Emergency Offer shall be considered available for scheduling and dispatch under both Emergency and non-Emergency conditions. Offers may only be designated as Maximum Emergency Offers to the extent that the Generation Capacity Resource falls into at least one of the following categories:

i) Environmental limits. If the resource has a limit on its run hours imposed by a federal, state or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited to operating only during declared PJM capacity emergencies by a governmental authority.

ii) Fuel limits. If physical events beyond the control of the resource owner result in the temporary interruption of fuel supply and there is limited on-site fuel storage. A fuel supplier's exercise of a contractual right to interrupt supply or delivery under an

interruptible service agreement shall not qualify as an event beyond the control of the resource owner.

iii) Temporary emergency conditions at the unit. If temporary emergency physical conditions at the resource significantly limit its availability.

iv) Temporary megawatt additions. If a resource can provide additional megawatts on a temporary basis by oil topping, boiler over-pressure, or similar techniques and such megawatts are not ordinarily otherwise available.

The submission of offers for resource increments that have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, and PJM Manuals, as applicable. Energy offered from generation resources that have not cleared a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region. The foregoing offers:

i) Shall specify the Generation Capacity Resource or Demand Resource and energy or demand reduction amount, respectively, for each hour in the offer period, and the minimum run time for generation resources and minimum down time for Demand Resources;

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

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

iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;

v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with a second schedule applicable if accepted after the foregoing deadline;

vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer, which offer shall remain open through the Operating Day for which the offer is submitted;

vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day; and

viii) Shall not exceed an energy offer price of $1,000/megawatt-hour for all generation resources and Demand Resources that have cleared a Base Residual Auction or an Incremental Auction.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation that shall specify the megawatt of Regulation being offered, which must equal or exceed 0.1 megawatts, the Regulation Zone for which such regulation is offered, the price of the capability offer in dollars per MW~~h~~, the price of the performance offer in Dollars per change in MW, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the resource's opportunity costs. The ~~price of the offer~~ total of the performance offer multiplied by the historical average mileage used in the market clearing plus the capability offer shall not exceed $100 per MWh in the case of Regulation offered for all Regulation Zones. In addition to any market-based offer for Regulation, the Market Seller also shall submit a cost-based offer. A cost-based offer must be in the form specified in the PJM Manuals and consist of the following components as well as any other components specified in the PJM Manuals:

i. The costs (in $/MW) of the fuel cost increase due to the heat rate increase resulting from operating a unit at lower megawatt output incurred from the provision of Regulation;

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

iii. An adder of up to $12.00 per megawatt of Regulation provided applied to the capability offer.

Qualified Regulation capability must satisfy the measurement and verification tests specified in the PJM Manuals.

(f) Each Market Seller owning or controlling the output of a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative shall submit a forecast of the availability of each such Generation Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with start-up and no-load fees, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours.

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

(h) The Office of the Interconnection shall post the total hourly loads scheduled in the Day-ahead Energy Market, as well as, its estimate of the combined hourly load of the Market Buyers for the next four days, and peak load forecasts for an additional three days.

(i) Except for Economic Load Response Participants, all Market Participants may submit Increment Bids and/or Decrement Bids that apply to the Day-ahead Energy Market only. Such bids must comply with the requirements set forth in the PJM Manuals and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-ahead Energy Market. The Office of the Interconnection may require that a market participant shall not submit in excess of 3000 bid/offer segments in the Day-ahead Energy Market, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to 10:00 a.m. EPT on the day that the Day-ahead Energy Market will clear. For purposes of this provision, a bid/offer segment is each pairing of price and megawatt quantity submitted as part of an Increment Bid or Decrement Bid.

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

(k) An Economic Load Response Participant that wishes to participate in the Day-ahead Energy Market by reducing demand shall submit an offer to reduce demand to the Office of the Interconnection. The offer must equal or exceed 0.1 megawatts, and the offer shall specify: (i) the amount of the offered curtailment in minimum increments of .1 megawatts: (ii) the Day-ahead Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, start-up costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum of number of contiguous hours for which the load reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs).

(l) Market Sellers owning or controlling the output of a Demand Resource that was committed in an FRR Capacity Plan, self-supplied or offered and cleared in the Base Residual Auction or one of the Incremental Auctions, or owning or controlling the output of an ILR resource which was certified as specified in Attachment DD of the PJM Tariff, may submit demand reduction bids for the available load reduction capability of the Demand Resource or

ILR resource. The submission of demand reduction bids for resource increments that have not cleared in the Base Residual Auction or in one of the Incremental Auctions, or for ILR resources that were not certified, or were not committed in an FRR Capacity Plan, shall be optional, but any such bids must contain the information specified in the PJM Economic Load Response Program to be included in such bids. A Demand Resource that was committed in an FRR Capacity Plan, self-supplied or offered and cleared in a Base Residual Auction or an Incremental Auction may submit a demand reduction bid in the Day-ahead Energy Market as specified in the Economic Load Response Program, provided however, that in the event of an Emergency, PJM shall require Demand Resources and ILR resources to reduce load notwithstanding that the Zonal LMP at the time such Emergency is declared is below the price identified in the demand reduction bid.

(m) Market Sellers that wish to make Day-ahead Scheduling Reserves Resources available to sell Day-ahead Scheduling Reserves shall submit offers, each of which must equal or exceed 0.1 megawatts, in the Day-ahead Scheduling Reserves Market specifying: 1) the price of the offer in dollars per megawatt hour; and 2) such other information specified by the Office of the Interconnection as may be necessary to determine any relevant opportunity costs for the resource(s). The foregoing notwithstanding, to qualify to submit offers pursuant to this section, the Day-ahead Scheduling Reserves Resources shall submit energy offers in the Day-ahead Energy Market including start-up and shut-down costs for generation resource and Demand Resources, respectively, and all generation resources that are capable of providing Day-ahead Scheduling Reserves that a particular resource can provide that service. The MW quantity of Day-ahead Scheduling Reserves that a particular resource can provide in a given hour will be determined based on the energy offer data submitted in the Day-ahead Energy Market, as detailed in the PJM Manuals.

1.10.2 Pool-scheduled Resources.

Pool-scheduled resources are those resources for which Market Participants submitted offers to sell energy in the Day-ahead Energy Market and offers to reduce demand in the Day-ahead Energy Market, which the Office of the Interconnection scheduled in the Day-ahead Energy Market as well as generators committed by the Office of the Interconnection subsequent to the Day-ahead Energy Market. Such resources shall be committed to provide energy in the real-time dispatch unless the schedules for such units are revised pursuant to Sections 1.10.9 or 1.11. Pool-scheduled resources shall be governed by the following principles and procedures.

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, start-up, no-load and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in Section 1.10.1A.

(b) A resource that is scheduled by a Market Participant to support a bilateral sale, or that is self-scheduled by a Generating Market Buyer, shall not be selected by the Office of the Interconnection as a pool-scheduled resource except in an Emergency.

(c) Market Sellers offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the Office of the Interconnection that is sufficient to enable the Office of the Interconnection to determine the available operating hours of such facilities.

(d) The Market Seller of a resource selected as a pool-scheduled resource shall receive payments or credits for energy, demand reductions or related services, or for start-up and no-load fees, from the Office of the Interconnection on behalf of the Market Buyers in accordance with Section 3 of this Schedule 1. Alternatively, the Market Seller shall receive, in lieu of start-up and no-load fees, its actual costs incurred, if any, up to a cap of the resource's start-up cost, if the Office of the Interconnection cancels its selection of the resource as a pool-scheduled resource and so notifies the Market Seller before the resource is synchronized.

(e) Market Participants shall make available their pool-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone.

(f) Economic Load Response Participants offering to reduce demand shall specify: (i) the amount of the offered curtailment, which offer must equal or exceed 0.1 megawatts, in minimum increments of .1 megawatts; (ii) the real-time Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, shut-down costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum number of contiguous hours for which the load reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Real-time Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs). Economic Load Response Participants offering to reduce demand shall also indicate the hours that the demand reduction is not available.

1.10.3 Self-scheduled Resources.

Self-scheduled resources shall be governed by the following principles and procedures.

(a) Each Generating Market Buyer shall use all reasonable efforts, consistent with Good Utility Practice, not to self-schedule resources in excess of its Equivalent Load.

(b) The offered prices of resources that are self-scheduled, or otherwise not following the dispatch orders of the Office of the Interconnection, shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.

(c) Market Participants shall make available their self-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone, by submitting an offer as to such resources.

(d) A Market Participant self-scheduling a resource in the Day-ahead Energy Market that does not deliver the energy in the Real-time Energy Market, shall replace the energy not

delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

1.10.4 Capacity Resources.

(a) A Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that is selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection. Such a Generation Capacity Resource that does not deliver energy as scheduled shall be deemed to have experienced a Generator Forced Outage to the extent of such energy not delivered. A Market Participant offering such Generation Capacity Resource in the Day-ahead Energy Market shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Energy from a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that has not been scheduled in the Day-ahead Energy Market may be sold on a bilateral basis by the Market Seller, may be self-scheduled, or may be offered for dispatch during the Operating Day in accordance with the procedures specified in this Schedule. Such a Generation Capacity Resource that has not been scheduled in the Day-ahead Energy Market and that has been sold on a bilateral basis must be made available upon request to the Office of the Interconnection for scheduling and dispatch during the Operating Day if the Office of the Interconnection declares a Maximum Generation Emergency. Any such resource so scheduled and dispatched shall receive the applicable Real-time Price for energy delivered.

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

1.10.5 External Resources.

(a) External Resources may submit offers to the PJM Interchange Energy Market, in accordance with the day-ahead and real-time scheduling processes specified above. An External Resource selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection, and except as specified below shall be compensated on the same basis as other pool-scheduled resources. External Resources that are not capable of dynamic dispatch shall, if selected by the Office of the Interconnection on the basis of the Market Seller's Offer Data, be block loaded on an hourly scheduled basis. Market Sellers shall offer External Resources to the PJM Interchange Energy Market on either a resource-specific or an aggregated resource basis. A Market Participant whose pool-scheduled resource does not deliver the energy scheduled in the Day-ahead Energy Market shall replace such energy not delivered as scheduled in the Day-ahead Energy Market with energy from the PJM Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Offers for External Resources from an aggregation of two or more generating units shall so indicate, and shall specify, in accordance with the Offer Data requirements specified by the Office of the Interconnection: (i) energy prices; (ii) hours of energy availability; (iii) a minimum

dispatch level; (iv) a maximum dispatch level; and (v) unless such information has previously been made available to the Office of the Interconnection, sufficient information, as specified in the PJM Manuals, to enable the Office of the Interconnection to model the flow into the PJM Region of any energy from the External Resources scheduled in accordance with the Offer Data.

(c) Offers for External Resources on a resource-specific basis shall specify the resource being offered, along with the information specified in the Offer Data as applicable.

1.10.6 External Market Buyers.

(a) Deliveries to an External Market Buyer not subject to dynamic dispatch by the Office of the Interconnection shall be delivered on a block loaded basis to the bus or buses at the electrical boundaries of the PJM Region, or in such area with respect to an External Market Buyer's load within such area not served by Network Service, at which the energy is delivered to or for the External Market Buyer. External Market Buyers shall be charged (which charge may be positive or negative) at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing bus or buses.

(b) An External Market Buyer's hourly schedules for energy purchased from the PJM Interchange Energy Market shall conform to the ramping and other applicable requirements of the interconnection agreement between the PJM Region and the Control Area to which, whether as an intermediate or final point of delivery, the purchased energy will initially be delivered.

(c) The Office of the Interconnection shall curtail deliveries to an External Market Buyer if necessary to maintain appropriate reserve levels for a Control Zone as defined in the PJM Manuals, or to avoid shedding load in such Control Zone.

1.10.6A Transmission Loading Relief Customers.

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

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

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

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

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

1.10.7 Bilateral Transactions.

Bilateral transactions as to which the parties have notified the Office of the Interconnection by the deadline specified in Section 1.10.1A that they elect not to be included in the Day-ahead Energy Market and that they are not willing to incur Transmission Congestion Charges in the Real-time Energy Market shall be curtailed by the Office of the Interconnection as necessary to reduce or alleviate transmission congestion. Bilateral transactions that were not included in the Day-ahead Energy Market and that are willing to incur congestion charges and bilateral transactions that were accepted in the Day-ahead Energy Market shall continue to be implemented during periods of congestion, except as may be necessary to respond to Emergencies.

1.10.8 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers and PRD Curves properly submitted by Load Serving Entities for the Price Responsive Demand loads they serve; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv) the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall

report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) Not earlier than 4:00 p.m. of the day before each Operating Day, or such other deadline as may be specified by the Office of the Interconnection in the PJM Manuals, the Office of the Interconnection shall: (i) post the aggregate Day-ahead Energy Market results; (ii) post the Day-ahead Prices; and (iii) inform the Market Sellers, Market Buyers, and Economic Load Response Participants of their scheduled injections, withdrawals, and demand reductions respectively.

(c) Following posting of the information specified in Section 1.10.8(b), the Office of the Interconnection shall revise its schedule of generation resources to reflect updated projections of load, conditions affecting electric system operations in the PJM Region, the availability of and constraints on limited energy and other resources, transmission constraints, and other relevant factors.

(d) Market Buyers shall pay PJMSettlement and Market Sellers shall be paid by PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the offer that set the Day-ahead Price is positive. Market Buyers shall be paid by PJMSettlement and Market Sellers shall pay PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the offer that set the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Section 3.3A of this Schedule.

(e) If the Office of the Interconnection discovers an error in prices and/or cleared quantities in the Day-ahead Energy Market, Real-time Energy Market, Ancillary Services Markets or Day Ahead Scheduling Reserve Market after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 12:00 p.m. of the second business day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the second business day following the initial publication of the results for the Day-ahead Scheduling Reserve Market and Day-ahead Energy Market. After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the fifth business day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the fifth business day following the initial publication of the results in the Day-ahead Scheduling Reserve Market and the Day-ahead Energy Market. Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating Day for the Ancillary Services Markets, Day-ahead Energy Market and Real-time Energy Market, and no later than 5:00 p.m. of the tenth calendar day following the initial publication of the results in the Day-ahead Scheduling Reserve Market. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced market results are under publicly noticed review by the FERC.

(f) Consistent with Section 18.17.1 of the PJM Operating Agreement, and notwithstanding anything to the contrary in the Operating Agreement or in the PJM Tariff, to allow the tracking of Market Participants' non-aggregated bids and offers over time as required by FERC Order No. 719, the Office of the Interconnection shall post on its Web site the non-aggregated bid data and Offer Data submitted by Market Participants (for participation in the PJM Interchange Energy Market) approximately four months after the bid or offer was submitted to the Office of the Interconnection.

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, a generation rebidding period shall exist from 4:00 p.m. to 6:00 p.m. on the day before each Operating Day. During the rebidding period, Market Participants may submit revisions to generation Offer Data for any generation resource that was not selected as a pool-scheduled resource in the Day-ahead Energy Market. Adjustments to Day-ahead Energy Markets shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 60 minutes prior to the hour in which the adjustment is to take effect, as follows:

i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;

ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or

iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or

iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any start-up fee.

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

(d) An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase in the Day-ahead Energy Market by notifying the Office of the Interconnection of the adjustment in deliveries not later than 60 minutes prior to the hour in which the adjustment is to take effect, but any such adjustment shall not affect the obligation of the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(e) For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section 1.10, the Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules for the hour.

1.11 Dispatch.

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

1.11.1 Resource Output.

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

1.11.2 Operating Basis.

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

1.11.3 Pool-dispatched Resources.

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

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

1.11.3A Maximum Generation Emergency.

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

1.11.4 Regulation.

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

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

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

1.11.4A Synchronized Reserve.

(a) A Market Buyer may satisfy its Synchronized Reserve Obligation from its own generation resources and/or Demand Resources capable of providing Synchronized Reserve, by

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

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

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

1.11.4B Non-Synchronized Reserve.

(a) A Market Buyer may satisfy its Non-Synchronized Reserve Obligation from its own generation resources and/or Demand Resources capable of providing Non-Synchronized Reserve, by contractual arrangements with other Market Participants able to provide Non-Synchronized Reserve, or by purchases from the PJM Non-Synchronized Reserve Market at the rates set forth in Section 3.2.3A.001.

(b) The Office of the Interconnection shall obtain Non-Synchronized Reserve from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Demand Resources as needed to ensure the Primary Reserve requirement of each Reserve Zone of the PJM Region not otherwise satisfied by the Market Buyers. Resources offering to sell Non-Synchronized Reserve shall be selected to provide Non-Synchronized Reserve on the basis of each generation resource's and/or Demand Resource's estimated unit specific opportunity cost of the resource providing Non-Synchronized Reserve, and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Synchronized Reserve and other ancillary services. Estimated unit specific opportunity costs for generation resources shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the absolute value of the difference between the Locational marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Non-Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources will be zero.

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

1.11.5 PJM Open Access Same-time Information System.

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

2.2 General.

The Office of the Interconnection shall determine the least cost security-constrained dispatch, which is the least costly means of serving load and meeting reserve requirements at different locations in the PJM Region based on actual operating conditions existing on the power grid (including transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6) and on the prices at which Market Sellers have offered to supply energy and offers by Economic Load Response Participants to reduce demand that qualify to set Locational Marginal Prices in the PJM Interchange Energy Market. Locational Marginal Prices for the generation and load busses in the PJM Region, including interconnections with other Control Areas, will be calculated based on the actual economic dispatch and the prices of energy and demand reduction offers. The process for the determination of Locational Marginal Prices shall be as follows:

(a) To determine actual operating conditions on the power grid in the PJM Region, the Office of the Interconnection shall use a computer model of the interconnected grid that uses available metered inputs regarding generator output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network. The computer model employed for this purpose, referred to as the State Estimator program, is a standard industry tool and is described in Section 2.3 below. It will be used to obtain information regarding the output of generation supplying energy to the PJM Region, loads at busses in the PJM Region, transmission losses, and power flows on binding transmission constraints for use in the calculation of Locational Marginal Prices. Additional information used in the calculation, including Dispatch Rates and real time schedules for external transactions between PJM and other Control Areas and dispatch and pricing information from entities with whom PJM has executed a joint operating agreement, will be obtained from the Office of the Interconnection's dispatchers.

(b) Using the prices at which energy is offered by Market Sellers and demand reductions are offered by Economic Load Response Participants to the PJM Interchange Energy Market, the Office of the Interconnection shall determine the offers of energy and demand reductions that will be considered in the calculation of Locational Marginal Prices. As described in Section 2.4 below, every qualified offer for demand reduction and of energy by a Market Seller from resources that are ~~following economic dispatch instructions of~~dispatched by the Office of the Interconnection will be utilized in the calculation of Locational Marginal Prices, including, without limitation, qualified offers from Economic Load Response Participants in either the Day-Ahead or Real-Time Energy Markets that satisfy the Net Benefits Test. Offers of ~~demand reduction~~economic load response from Demand Resources in the Real-time Energy Market will not be eligible to set Locational Marginal Prices, unless metered directly by the Office of the Interconnection. Offers of Full Program Option resources in the Emergency Load Response Program are eligible to set real time Locational Marginal Prices when the Office of the Interconnection has implemented Emergency procedures and such resources are required to reduce demand in the PJM Region, so long as sufficient data is available to accurately model the resources.

(c) Based on the system conditions on the PJM power grid, determined as described in (a), and the eligible energy and demand reduction offers, determined as described in (b), the Office of the Interconnection shall determine the least costly means of obtaining energy to serve the next increment of load at each bus in the PJM Region, in the manner described in Section 2.5 below. The result of that calculation shall be a set of Locational Marginal Prices based on the system conditions at the time.

2.3 Determination of System Conditions Using the State Estimator.

Power system operations, including, but not limited to, the determination of the least costly means of serving load and meeting reserve requirements, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In calculating Locational Marginal Prices, the Office of the Interconnection shall obtain a complete and consistent description of conditions on the electric network in the PJM Region by using the most recent power flow solution produced by the State Estimator program and utilized in the PJM dispatch algorithm, which State Estimator program is also used by the Office of the Interconnection for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available real-time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at busses for which real-time information is unavailable. The Office of the Interconnection shall obtain a State Estimator solution every five minutes, which shall provide the megawatt output of generators and the loads at busses in the PJM Region, transmission line losses, and actual flows or loadings on constrained transmission facilities. External transactions between PJM and other Control Areas shall be included in the Locational Marginal Price calculation on the basis of the real time transaction schedules implemented by the Office of the Interconnection's dispatcher.

2.4 Determination of Energy Offers Used in Calculating Real-time Prices.

(a) During the Operating Day, real-time Locational Marginal Prices derived in accordance with this Section shall be determined every five minutes and integrated hourly values of such determinations shall be the basis of sales and purchases of energy in the Real-time Energy Market and of Transmission Congestion Charges under the PJM Tariff not covered by the Day-ahead Energy Market.

(b) To determine the energy offers submitted to the PJM Interchange Energy Market that shall be used during the Operating Day to calculate the Real-time Prices, the Office of the Interconnection shall determine the applicable marginal energy offer of the~~which~~ resources being dispatched by the Office of the Interconnection~~are following its economic dispatch instructions~~. A resource ~~will be considered to be following economic dispatch instructions and~~ shall be included in the calculation of Real-time Prices if ~~:~~

~~i)~~ the applicable marginal energy offer of the ~~price bid by a Market Seller for energy from the~~ resource being dispatched by the Office of the Interconnection is less than or equal to the Dispatch Rate for the area of the PJM Region in which the resource is located.~~; or~~

~~ii) the resource is specifically requested to operate by the Office of the Interconnection's dispatcher.~~

(c) In determining whether a resource satisfies the condition described in (b), the Office of the Interconnection will determine the ~~bid price associated with an~~ applicable marginal energy offer by comparing the ~~actual~~ requested megawatt output of the resource with the Market Seller's offer price curve. ~~Because of practical generator response limitations, a resource whose megawatt output is not ten percent more than the megawatt level specified on the offer price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but t~~The applicable marginal energy ~~price~~ offer used in the calculation of Real-time Prices shall not exceed the applicable Dispatch Rate. Units that must be run for local area protection shall not be considered in the calculation of Real-time Prices.

2.5 Calculation of Real-time Prices.

(a) The Office of the Interconnection shall determine the least costly means of obtaining energy to serve the next increment of load (taking account of any applicable and available load reductions indicated on PRD Curves properly submitted by any PRD Provider) at each bus in the PJM Region represented in the State Estimator and each Interface Pricing Point between PJM and an adjacent Control Area, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and utilized in the PJM dispatch algorithm and the energy offers that are the basis for the Day-ahead Energy Market, or that are determined to be eligible for consideration under Section 2.4 in connection with the real-time dispatch, as applicable. This calculation shall be made by applying ~~an incremental linear optimization method to minimize energy costs~~ a real-time joint optimization of energy and reserves, given actual system conditions, a set of energy offers, a set of reserve offers, a set of Reserve Penalty Factors, and any binding transmission constraints that may exist. In performing this calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a generation resource or decrease an increment of energy being consumed by a Demand Resource, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses. The real-time Locational Marginal Prices at a bus shall be determined through the joint optimization based on the lowest marginal cost to serve the next increment of load at the bus taking into account the applicable reserve requirements, unit resource constraints, transmission constraints and marginal loss impact.~~The energy offer or offers that can serve an increment of load at a bus at the lowest cost, calculated in this manner, shall determine the Real-time Price at that bus.~~

(b) If all reserve requirements in every modeled Reserve Zone can be met at prices less than or equal to the energy offer cap of $1,000 per megawatt-hour, real-time Locational Marginal Prices shall be calculated as described in Section 2.5(a) above. When a reserve requirement cannot be met at a price less than or equal to be met at prices less than or equal to the energy offer cap of $1,000 per megawatt-hour, the real-time Locational Marginal Prices shall be capped at $1,000 per megawatt-hour.

(~~b~~c) During the Operating Day, the calculation set forth in (a) shall be performed every five minutes, using the Office of the Interconnection's Locational Marginal Price program, producing a set of Real-time Prices based on system conditions during the preceding interval. The prices produced at five-minute intervals during an hour will be integrated to determine the Real-time Prices for that hour.

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 ~~at~~: (i) the capability Regulation market-clearing price determined in accordance with subsection (~~e~~g) of this section; ~~, plus~~ the amounts, if any, described in subsection (~~f~~e) of this section; and (iii) the Internal Market Buyer's pro rata share of any performance credits paid to regulating resources calculated in accordance with subsection (f) of this section.

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

(c) The 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 (f) 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 ~~highest sum of a resource's Regulation offer plus its estimated~~ unit-specific opportunity costs, during the 5-minute period determined as described in subsection (d) below from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.3.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation 5-minute ~~market~~ clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour shall be equal to ~~the sum of the unit-specific opportunity costs (i)~~

~~incurred during the hour in which the obligation is fulfilled, plus costs (ii) associated with uneconomic operation during the hour preceding the initial regulating hour ("preceding shoulder hour"), plus costs (iii) associated with uneconomic operation during the hour after the final regulating hour ("following shoulder hour").~~

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

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

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

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

~~(e) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Regulation, and for the percentage of the preceding shoulder hour and the following shoulder hour during which the Generating Market Buyer or Market Seller provided Regulation. The unit-specific opportunity cost incurred during the hour in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of~~

~~the generation resource's output necessary to follow the Office of the Interconnection's Regulation signals from the generation resource's expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.~~

~~The unit-specific opportunity costs associated with uneconomic operation during the preceding shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the preceding shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the preceding shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the preceding shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.~~

~~The unit-specific opportunity costs associated with uneconomic operation during the following shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating hour in order to provide Regulation and the lesser of the resource's actual or expected output in the following shoulder hour when the resource is requested at a lower output than what is otherwise economic in order to provide Regulation, or, the higher of the resource's actual or expected output in the following shoulder hour when the resource is requested at a higher output than what is otherwise economic in order to provide Regulation, times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in the following shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market, times (iii) the percentage of the following shoulder hour during which the deviation was incurred, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.~~

(~~f~~e) 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.

(f) 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 expected amount of Regulation that resource will be dispatched based on the historical ratio of control signals calculated by the Office of the Interconnection, and the ratio of benefits to system control for following the Regulation control signal 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 based on the assigned MW(s), the performance Regulation market-clearing price, the amount of Regulation performance of the resource provides during the market hour, and the accuracy with which each resource responds to the Office of the Interconnection's Regulation signals during the market hour.

(g) 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 (f) 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 capacity Regulation market-clearing price.

(h) 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.

(i) If PJM is unable to meet its Synchronized Reserve requirements as specified in 1.7.19A, the performance Regulation clearing price and the capability Regulation clearing price will be held steady for the duration of the reserve deficiency at the last value calculated prior to the start of the reserve deficiency. In the event of such reserve deficiency, 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 at the higher of (i) the Regulation market-clearing price in such Regulation Zone or (ii) the sum of the regulation offer and the unit-specific opportunity cost of the generation resource supplying the increment of Regulation.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to section 1.10.1A(e) of this Schedule. A Regulation supplier fails the three-pivotal supplier test in any hour in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

(b) For the purposes of conducting the three-pivotal supplier test pursuant to this section, the following applies:

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region for which the 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.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Section 3.2.3A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the Day-ahead Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load fees and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds

the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve credits, identified as RA Credits for Reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or

exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

(c) The sum of the foregoing credits calculated in accordance with Section 3.2.3(b) plus any unallocated charges from Section 3.2.3(h) and 5.1.7, and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program shall be the cost of Operating Reserves in the Day-ahead Energy Market.

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following segments: 1) the greater of their day-ahead schedules or minimum run time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or minimum run time (minimum down time for Demand Resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time (minimum down time for Demand Resources) and Segment 2 will include the remainder of the contiguous hours when the resource is operating at the direction of the Office of the Interconnection, provided that a

segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

Credits received pursuant to this section shall be equal to the positive difference between a resource's total offered price for start-up (shutdown costs for Demand Resources) and no-load fees and energy, determined on the basis of the resource's scheduled output, and the total value of the resource's energy as determined by the Real-time Energy Market and the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for segment 2 shall exclude start up (shutdown costs for Demand Resources) costs for generation resources.

Except as provided in Section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to Section 3.2.3(b) plus the resource's opportunity cost and less any amounts credited for Synchronized Reserve in excess of the Synchronized Reserve offer plus the resource's opportunity cost and less any amounts credited for providing Reactive Services as specified in Section 3.2.3B, and less any amounts for Day-ahead Scheduling Reserve in excess of the Day-ahead Scheduling Reserve offer plus the resource's opportunity cost, shall be credited to the Market Seller.

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

(f) A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

AG equals the actual hourly integrated output of the unit;

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

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

where URTLMP - UB shall not be negative.

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

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described above for a steam unit or combined cycle unit operating in combined cycle mode.

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

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

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

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

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

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

(f-2) A Market Seller's hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a

transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves, plus any redispatch costs incurred in accordance with section 10(a) of this Schedule, shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (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.

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 busses that define all interfaces or all hubs are located in the region. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by busses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed in accordance with the following provisions:

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of an Operating Reserve shortage in real-time or where PJM initiates the request for load reductions in real-time in order to avoid an Operating Reserve shortage as described in this Schedule, Section 6A, Scarcity Pricing.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in Section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for the PJM Region.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in

proportion to the sum of its (i) deliveries of energy to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside the PJM Region pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared ("Maximum Generation Emergency Alert"); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the Operating Reserves credit otherwise provided by Section 3.2.3.(b) or Section 3.2.3(e) in connection with marked-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as "MaxGen Conditions"). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Schedule 2 of the Operating Agreement, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatt hours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any hours required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon on

the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described in the PJM Manuals. Ramp-limited desired MW values shall be used to determine generation resource real-time deviations from the resource's day-ahead schedules.

The Office of the Interconnection shall calculate a ramp-limited desired MW value for generation resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:

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

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

$$Ramp_Request_t = (UDStarget_{t-1} - AOutput_{t-1}) \Big/ (UDSLAtime_{t-1})$$

$$RL_Desired_t = AOutput_{t-1} + \left(Ramp_Request_t * Case_Eff_time_{t-1} \right)$$

where:

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

To determine if a 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 Interconnection will determine the unit's MWoff dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the UDS LMP Desired MW.

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and UDS Basepoint, or if its % off dispatch is <= 10, or 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 <= 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 n 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 to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve charges shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve charges shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve charges shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges

for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region. For the purposes of this section, the Western Region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, DEOK transmission Zones, and the Eastern Region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones. The regional balancing Operating Reserve rates shall be determined in accordance with the following provisions:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

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

(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.

3.2.3A Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Synchronized Reserve Zone of the PJM Region, based on the Market

Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Synchronized Reserve Zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). An Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts if any, described in subsections (g), (h) and (i) of this section.

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

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

ii) Credits for Synchronized Reserve provided by generation resources that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the Interconnection energy dispatch signals and instructions ("Tier 2 Synchronized Reserve") shall be the higher of (i) the Synchronized Reserve Market Clearing Price or (ii) the sum of (A) the Synchronized Reserve offer, and (B) the specific opportunity cost of the generation resource supplying the increment of Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

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

(c) The Synchronized Reserve Energy Premium Price is the average of the five-minute Locational Marginal Prices calculated during the Synchronized Reserve Event plus an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Synchronized Reserve Zone by the Office of the Interconnection prior to the operating hour and such market-clearing price shall be equal to, from among the generation resources or Demand

Resources selected to provide Synchronized Reserve for such Synchronized Reserve Zone, the highest sum of either (i) a generation resource's Synchronized Reserve offer and opportunity cost or (ii) a demand response resource's Synchronized Reserve offer.

(e) In determining the 5-minute Synchronized Reserve ~~Market Clearing~~ clearing ~~Price~~price, the estimated unit-specific opportunity cost for a generation resource shall be equal to the sum of (i) the product of (A) the expected Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

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

(g) Charges for Tier 1 Synchronized Reserve will be allocated in proportion to the amount of Tier 1 Synchronized Reserve applied to each Synchronized Reserve Obligation. In the event Tier 1 Synchronized Reserve is provided by a Market Seller in excess of that Market Seller's Synchronized Reserve Obligation, the remainder of the Tier 1 Synchronized Reserve that is not utilized to fulfill the Seller's obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

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

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

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

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l) is the difference between the generation resource's output or the Demand Resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load Demand Resource's consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Demand Resource's

consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.

(m) If PJM is unable to meet its Synchronized Reserve requirements as specified in 1.7.19A, the Synchronized Reserve Market Clearing Price will be held steady for the duration of the reserve deficiency at the last value calculated prior to the start of the reserve deficiency.

3.2.3A.01 Day-ahead Scheduling Reserves.

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

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

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

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

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

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

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

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

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

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

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

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit hourly in an amount equal to {(LMPDMW - AG) x (URTLMP - UB)}

where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

AG equals the actual hourly integrated output of the unit;

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

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

where URTLMP - UB shall not be negative.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

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

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

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

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

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

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

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to Section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or

as directed by the PJM dispatcher through a manual override), shall receive a credit hourly in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual hourly integrated output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any regulation or Tier 2 Synchronized Reserve assignments;

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

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

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose

of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generation unit's bus, (C) the generation unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the

Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations

of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

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

3.2.5 Transmission Loss Charges.

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

3.2.6 Emergency Energy.

(a) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each hour of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(b) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each hour of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market

sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(c) The net costs or net revenues associated with sales or purchases of hourly energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each hour of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Buyer in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market Buyer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Buyer's internal accounting.

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

SCHEDULE 3
Regulation and Frequency Response Service

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

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

a. Regulation shall be supplied to meet the Regulation objective of a Regulation Zone from resources located within the metered electrical boundaries of such Regulation Zone. Resources offering Regulation shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the PJM Manuals.

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

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

d. A resource capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced from the Regulation range by at least twice the amount of the Regulation provided with consideration of the Regulation limits of the resource, as specified in the PJM Manuals.

e. Qualified Regulation must satisfy the measurement and verification tests described in the PJM Manuals.

f. A Transmission Owner, Network Customer or other Transmission Customer may satisfy its Regulation obligation from its own resources capable of performing Regulation service, by contractual arrangements with others able to provide Regulation service on a comparable basis, or by purchases from the PJM Regulation market.

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

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

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

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

1.7 General.

1.7.1 Market Sellers.

Only Market Sellers shall be eligible to submit offers to the Office of the Interconnection for the sale of electric energy or related services in the PJM Interchange Energy Market. Market Sellers shall comply with the prices, terms, and operating characteristics of all Offer Data submitted to and accepted by the PJM Interchange Energy Market.

1.7.2 Market Buyers.

Only Market Buyers shall be eligible to purchase energy or related services in the PJM Interchange Energy Market. Market Buyers shall comply with all requirements for making purchases from the PJM Interchange Energy Market.

1.7.2A Economic Load Response Participants.

Only Economic Load Response Participants shall be eligible to participate in the Real-time Energy Market and the Day-ahead Energy Market by submitting offers to the Office of the Interconnection to reduce demand.

1.7.3 Agents.

A Market Participant may participate in the PJM Interchange Energy Market through an agent, provided that the Market Participant informs the Office of the Interconnection in advance in writing of the appointment of such agent. A Market Participant participating in the PJM Interchange Energy Market through an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the PJM Interchange Energy Market, and shall ensure that any such agent complies with the requirements of this Agreement.

1.7.4 General Obligations of the Market Participants.

(a) In performing its obligations to the Office of the Interconnection hereunder, each Market Participant shall at all times (i) follow Good Utility Practice, (ii) comply with all applicable laws and regulations, (iii) comply with the applicable principles, guidelines, standards and requirements of FERC, NERC and Applicable Regional Reliability Councils, (iv) comply with the procedures established for operation of the PJM Interchange Energy Market and PJM Region and (v) cooperate with the Office of the Interconnection as necessary for the operation of the PJM Region in a safe, reliable manner consistent with Good Utility Practice.

(b) Market Participants shall undertake all operations in or affecting the PJM Interchange Energy Market and the PJM Region including but not limited to compliance with all

Emergency procedures, in accordance with the power and authority of the Office of the Interconnection with respect to the operation of the PJM Interchange Energy Market and the PJM Region as established in this Agreement, and as specified in the Schedules to this Agreement and the PJM Manuals. Failure to comply with the foregoing operational requirements shall subject a Market Participant to such reasonable charges or other remedies or sanctions for non-compliance as may be established by the PJM Board, including legal or regulatory proceedings as authorized by the PJM Board to enforce the obligations of this Agreement.

(c) The Office of the Interconnection may establish such committees with a representative of each Market Participant, and the Market Participants agree to provide appropriately qualified personnel for such committees, as may be necessary for the Office of the Interconnection and PJMSettlement to perform its obligations hereunder.

(d) All Market Participants shall provide to the Office of the Interconnection the scheduling and other information specified in the Schedules to this Agreement, and such other information as the Office of the Interconnection may reasonably require for the reliable and efficient operation of the PJM Region and PJM Interchange Energy Market, and for compliance with applicable regulatory requirements for posting market and related information. Such information shall be provided as much in advance as possible, but in no event later than the deadlines established by the Schedules to this Agreement, or by the Office of the Interconnection in conformance with such Schedules. Such information shall include, but not be limited to, maintenance and other anticipated outages of generation or transmission facilities, scheduling and related information on bilateral transactions and self-scheduled resources, and implementation of active load management, interruption of load, Price Responsive Demand, and other load reduction measures. The Office of the Interconnection shall abide by appropriate requirements for the non-disclosure and protection of any confidential or proprietary information given to the Office of the Interconnection by a Market Participant. Each Market Participant shall maintain or cause to be maintained compatible information and communications systems, as specified by the Office of the Interconnection, required to transmit scheduling, dispatch, or other time-sensitive information to the Office of the Interconnection in a timely manner.

(e) Subject to the requirements for Economic Load Response Participants in section 1.5A above, each Market Participant shall install and operate, or shall otherwise arrange for, metering and related equipment capable of recording and transmitting all voice and data communications reasonably necessary for the Office of the Interconnection and PJMSettlement to perform the services specified in this Agreement. A Market Participant that elects to be separately billed for its PJM Interchange shall, to the extent necessary, be individually metered in accordance with Section 14 of this Agreement, or shall agree upon an allocation of PJM Interchange between it and the Market Participant through whose meters the unmetered Market Participant's PJM Interchange is delivered. The Office of the Interconnection shall be notified of the allocation by the foregoing Market Participants.

(f) Each Market Participant shall operate, or shall cause to be operated, any generating resources owned or controlled by such Market Participant that are within the PJM Region or otherwise supplying energy to or through the PJM Region in a manner that is

consistent with the standards, requirements or directions of the Office of the Interconnection and that will permit the Office of the Interconnection to perform its obligations under this Agreement; provided, however, no Market Participant shall be required to take any action that is inconsistent with Good Utility Practice or applicable law.

(g) Each Market Participant shall follow the directions of the Office of the Interconnection to take actions to prevent, manage, alleviate or end an Emergency in a manner consistent with this Agreement and the procedures of the PJM Region as specified in the PJM Manuals.

(h) Each Market Participant shall obtain and maintain all permits, licenses or approvals required for the Market Participant to participate in the PJM Interchange Energy Market in the manner contemplated by this Agreement.

(i) Consistent with Section 36.1.1 of the PJM Tariff, to the extent its generating facility is dispatchable, a Market Participant shall submit an Economic Minimum in the Real-time Energy Market that is no greater than the higher of its physical operating minimum or its Capacity Interconnection Rights, as that term is defined in the PJM Tariff, associated with such generating facility under its Interconnection Service Agreement under Attachment O of the PJM Tariff or a wholesale market participation agreement.

1.7.5 Market Operations Center.

Each Market Participant shall maintain a Market Operations Center, or shall make appropriate arrangements for the performance of such services on its behalf. A Market Operations Center shall meet the performance, equipment, communications, staffing and training standards and requirements specified in this Agreement for the scheduling and completion of transactions in the PJM Interchange Energy Market and the maintenance of the reliable operation of the PJM Region, and shall be sufficient to enable (i) a Market Seller or an Economic Load Response Participant to perform all terms and conditions of its offers to the PJM Interchange Energy Market, and (ii) a Market Buyer or an Economic Load Response Participant to conform to the requirements for purchasing from the PJM Interchange Energy Market.

1.7.6 Scheduling and Dispatching.

(a) The Office of the Interconnection shall schedule and dispatch in real-time generation resources and/or Demand Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Sellers, continuing until sufficient generation resources and/or Demand Resources are dispatched to serve the PJM Interchange Energy Market energy purchase requirements under normal system conditions of the Market Buyers (taking into account any reductions to such requirements in accordance with PRD Curves properly submitted by PRD Providers), as well as the requirements of the PJM Region for ancillary services provided by generation resources and/or Demand Resources, in accordance with this Agreement. Such scheduling and dispatch shall recognize transmission constraints on coordinated flowgates external to the Transmission System in

accordance with Appendix A to the Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38) and on other such flowgates that are coordinated in accordance with agreements between the LLC and other entities. Scheduling and dispatch shall be conducted in accordance with this Agreement.

(b) The Office of the Interconnection shall undertake to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the PJM Interchange Energy Market, and any relevant procedures of another Control Area, or any tariff (including the PJM Tariff). Upon determining that any such conflict or incompatibility exists, the Office of the Interconnection shall propose tariff or procedural changes, and undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

(c) To protect its generation or distribution facilities, or local Transmission Facilities not under the monitoring responsibility and dispatch control of the Office of the Interconnection, an entity may request that the Office of the Interconnection schedule and dispatch generation or reductions in demand to meet a limit on Transmission Facilities different from that which the Office of the Interconnection has determined to be required for reliable operation of the Transmission System. To the extent consistent with its other obligations under this Agreement, the Office of the Interconnection shall schedule and dispatch generation and reductions in demand in accordance with such request. An entity that makes a request pursuant to this section 1.7.6(c) shall be responsible for all generation and other costs resulting from its request that would not have been incurred by operating the Transmission System and scheduling and dispatching generation in the manner that the Office of the Interconnection otherwise has determined to be required for reliable operation of the Transmission System.

1.7.7 Pricing.

The price paid for energy bought and sold in the PJM Interchange Energy Market and for demand reductions will reflect the hourly Locational Marginal Price at each load and generation bus, determined by the Office of the Interconnection in accordance with this Agreement. Transmission Congestion Charges and Transmission Loss Charges, which shall be determined by differences in Congestion Prices and Loss Prices in an hour, shall be calculated by the Office of the Interconnection, and collected by PJMSettlement, and the revenues therefrom shall be disbursed by PJMSettlement in accordance with this Schedule.

1.7.8 Generating Market Buyer Resources.

A Generating Market Buyer may elect to self-schedule its generation resources up to that Generating Market Buyer's Equivalent Load, in accordance with and subject to the procedures specified in this Schedule, and the accounting and billing requirements specified in Section 3 to this Schedule. PJMSettlement shall not be a contracting party with respect to such self-scheduled or self-supplied transactions.

1.7.9 Delivery to an External Market Buyer.

A purchase of Spot Market Energy by an External Market Buyer shall be delivered to a bus or busses at the electrical boundaries of the PJM Region specified by the Office of the Interconnection, or to load in such area that is not served by Network Transmission Service, using Point-to-Point Transmission Service paid for by the External Market Buyer. Further delivery of such energy shall be the responsibility of the External Market Buyer.

1.7.10 Other Transactions.

(a) Bilateral Transactions.

(i) In addition to transactions in the PJM Interchange Energy Market, Market Participants may enter into bilateral contracts for the purchase or sale of electric energy to or from each other or any other entity, subject to the obligations of Market Participants to make Generation Capacity Resources available for dispatch by the Office of the Interconnection. Such bilateral contracts shall be for the physical transfer of energy to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its eSchedules and Enhanced Energy Scheduler tools.

(ii) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of energy to a Market Participant inside the PJM Region, title to the energy that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and the further transmission of the energy or further sale of the energy into the PJM Interchange Energy Market shall be transacted by the buyer under the bilateral contract. With respect to all bilateral contracts for the physical transfer of energy to an entity outside the PJM Region, title to the energy shall pass to the buyer at the border of the PJM Region and shall be delivered to the border using transmission service. In no event shall the purchase and sale of energy between Market Participants under a bilateral contract constitute a transaction in the PJM Interchange Energy Market or be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

(iii) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of energy reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the megawatt hours of such reported transactions to amounts reflecting the expected load and other physical delivery obligations of the buyer under the bilateral contract.

(iv) All payments and related charges for the energy associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. 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 a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

(v) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any Spot Market Backup used to meet the bilateral contract seller's obligation to deliver energy under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new eSchedules or Enhanced Energy Scheduler reporting by the Market Participant and (ii) terminate all of the Market Participant's eSchedules and Enhanced Energy Schedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the eSchedules and Enhanced Energy Schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection. PJMSettlement shall assign its claims against a seller with respect to a seller's nonpayment for Spot Market Backup to a buyer to the extent that the buyer has made an indemnification payment to PJMSettlement with respect to the seller's nonpayment.

(vi) Bilateral contracts that do not contemplate the physical transfer of energy to or from a Market Participant are not subject to this Schedule, shall not be reported to and coordinated with the Office of the Interconnection, and shall not in any way constitute a transaction in the PJM Interchange Energy Market.

(b) Market Participants shall have Spot Market Backup with respect to all bilateral transactions that contemplate the physical transfer of energy to or from a Market Participant, that are not dynamically scheduled pursuant to Section 1.12 and that are curtailed or interrupted for any reason (except for curtailments or interruptions through active load management for load located within the PJM Region).

(c) To the extent the Office of the Interconnection dispatches a Generating Market Buyer's generation resources, such Generating Market Buyer may elect to net the output of such resources against its hourly Equivalent Load. Such a Generating Market Buyer shall be deemed a buyer from the PJM Interchange Energy Market to the extent of its PJM Interchange Imports, and shall be deemed a seller to the PJM Interchange Energy Market to the extent of its PJM Interchange Exports.

(d) A Market Seller may self-supply Station Power for its generation facility in accordance with the following provisions:

(i) A Market Seller may self-supply Station Power for its generation facility during any month (1) when the net output of such facility is positive, or (2) when the net output of such facility is negative and the Market Seller during the same month has available at other of its generation facilities positive net output in an amount at least sufficient to offset fully such negative net output. For purposes of this subsection (d), "net output" of a generation facility during any month means the facility's gross energy

output, less the Station Power requirements of such facility, during that month. The determination of a generation facility's or a Market Seller's monthly net output under this subsection (d) will apply only to determine whether the Market Seller self-supplied Station Power during the month and will not affect the price of energy sold or consumed by the Market Seller at any bus during any hour during the month. For each hour when a Market Seller has positive net output and delivers energy into the Transmission System, it will be paid the LMP at its bus for that hour for all of the energy delivered. Conversely, for each hour when a Market Seller has negative net output and has received Station Power from the Transmission System, it will pay the LMP at its bus for that hour for all of the energy consumed.

(ii) Transmission Provider will determine the extent to which each affected Market Seller during the month self-supplied its Station Power requirements or obtained Station Power from third-party providers (including affiliates) and will incorporate that determination in its accounting and billing for the month. In the event that a Market Seller self-supplies Station Power during any month in the manner described in subsection (1) of subsection (d)(i) above, Market Seller will not use, and will not incur any charges for, transmission service. In the event, and to the extent, that a Market Seller self-supplies Station Power during any month in the manner described in subsection (2) of subsection (d)(i) above (hereafter referred to as "remote self-supply of Station Power"), Market Seller shall use and pay for transmission service for the transmission of energy in an amount equal to the facility's negative net output from Market Seller's generation facility(ies) having positive net output. Unless the Market Seller makes other arrangements with Transmission Provider in advance, such transmission service shall be provided under Part II of the PJM Tariff and shall be charged the hourly rate under Schedule 8 of the PJM Tariff for Non-Firm Point-to-Point Transmission Service with an election to pay congestion charges, provided, however, that no reservation shall be necessary for such transmission service and the terms and charges under Schedules 1, 1A, 2 through 6, 9 and 10 of the PJM Tariff shall not apply to such service. The amount of energy that a Market Seller transmits in conjunction with remote self-supply of Station Power will not be affected by any other sales, purchases, or transmission of capacity or energy by or for such Market Seller under any other provisions of the PJM Tariff.

(iii) A Market Seller may self-supply Station Power from its generation facilities located outside of the PJM Region during any month only if such generation facilities in fact run during such month and Market Seller separately has reserved transmission service and scheduled delivery of the energy from such resource in advance into the PJM Region.

1.7.11 Emergencies.

(a) The Office of the Interconnection, with the assistance of the Members' dispatchers as it may request, shall be responsible for monitoring the operation of the PJM Region, for declaring the existence of an Emergency, and for directing the operations of Market Participants as necessary to manage, alleviate or end an Emergency. The standards, policies and procedures of the Office of the Interconnection for declaring the existence of an Emergency,

including but not limited to a Minimum Generation Emergency, and for managing, alleviating or ending an Emergency, shall apply to all Members on a non-discriminatory basis. Actions by the Office of the Interconnection and the Market Participants shall be carried out in accordance with this Agreement, the NERC Operating Policies, Applicable Regional Reliability Council reliability principles and standards, Good Utility Practice, and the PJM Manuals. A declaration that an Emergency exists or is likely to exist by the Office of the Interconnection shall be binding on all Market Participants until the Office of the Interconnection announces that the actual or threatened Emergency no longer exists. Consistent with existing contracts, all Market Participants shall comply with all directions from the Office of the Interconnection for the purpose of managing, alleviating or ending an Emergency. The Market Participants shall authorize the Office of the Interconnection and PJMSettlement to purchase or sell energy on their behalf to meet an Emergency, and otherwise to implement agreements with other Control Areas interconnected with the PJM Region for the mutual provision of service to meet an Emergency, in accordance with this Agreement.

(b) To the extent load must be shed to alleviate an Emergency in a Control Zone, the Office of the Interconnection shall, to the maximum extent practicable, direct the shedding of load within such Control Zone. The Office of the Interconnection may shed load in one Control Zone to alleviate an Emergency in another Control Zone under its control only as necessary after having first shed load to the maximum extent practicable in the Control Zone experiencing the Emergency and only to the extent that PJM supports other control areas (not under its control) in those situations where load shedding would be necessary, such as to prevent isolation of facilities within the Eastern Interconnection, to prevent voltage collapse, or to restore system frequency following a system collapse; provided, however, that the Office of the Interconnection may not order a manual load dump in a Control Zone solely to address capacity deficiencies in another Control Zone. This section shall be implemented consistent with the North American Electric Reliability Council and applicable reliability council standards.

1.7.12 Fees and Charges.

Each Market Participant, except for Special Members, shall pay all fees and charges of the Office of the Interconnection for operation of the PJM Interchange Energy Market as determined by and allocated to the Market Participant by the Office of the Interconnection in accordance with Schedule 3.

1.7.13 Relationship to the PJM Region.

The PJM Interchange Energy Market operates within and subject to the requirements for the operation of the PJM Region.

1.7.14 PJM Manuals.

The Office of the Interconnection shall be responsible for maintaining, updating, and promulgating the PJM Manuals as they relate to the operation of the PJM Interchange Energy Market. The PJM Manuals, as they relate to the operation of the PJM Interchange Energy Market, shall conform and comply with this Agreement, NERC operating policies, and

Applicable Regional Reliability Council reliability principles, guidelines and standards, and shall be designed to facilitate administration of an efficient energy market within industry reliability standards and the physical capabilities of the PJM Region.

1.7.15 Corrective Action.

Consistent with Good Utility Practice, the Office of the Interconnection shall be authorized to direct or coordinate corrective action, whether or not specified in the PJM Manuals, as necessary to alleviate unusual conditions that threaten the integrity or reliability of the PJM Region, or the regional power system.

1.7.16 Recording.

Subject to the requirements of applicable State or federal law, all voice communications with the Office of the Interconnection Control Center may be recorded by the Office of the Interconnection and any Market Participant communicating with the Office of the Interconnection Control Center, and each Market Participant hereby consents to such recording.

1.7.17 Operating Reserves.

(a) The following procedures shall apply to any generation unit subject to the dispatch of the Office of the Interconnection for which construction commenced before July 9, 1996, or any Demand Resource subject to the dispatch of the Office of the Interconnection.

(b) The Office of the Interconnection shall schedule to the Operating Reserve and load-following objectives of the Control Zones of the PJM Region and the PJM Interchange Energy Market in scheduling generation resources and/or Demand Resources pursuant to this Schedule. A table of Operating Reserve objectives for each Control Zone is calculated and published annually in the PJM Manuals. Reserve levels are probabilistically determined based on the season's historical load forecasting error and forced outage rates.

(c) Nuclear generation resources shall not be eligible for Operating Reserve payments unless: 1) the Office of the Interconnection directs such resources to reduce output, in which case, such units shall be compensated in accordance with section 3.2.3(f) of this Schedule; or 2) the resource submits a request for a risk premium to the Market Monitoring Unit under the procedures specified in Section II.B of Attachment M - Appendix. A nuclear generation resource (i) must submit a risk premium consistent with its agreement under such process, or, (ii) if it has not agreed with the Market Monitoring Unit on an appropriate risk premium, may submit its own determination of an appropriate risk premium to the Office of the Interconnection, subject to acceptance by the Office of the Interconnection, with or without prior approval from the Commission.

(d) PJMSettlement shall be the Counterparty to the purchases and sales of Operating Reserve in the PJM Interchange Energy Market.

1.7.18 Regulation.

(a) Regulation to meet the Regulation objective of each Regulation Zone shall be supplied from generation resources and/or Demand Resources located within the metered electrical boundaries of such Regulation Zone. Generating Market Buyers, and Market Sellers offering Regulation, shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the PJM Manuals.

(b) The Office of the Interconnection shall obtain and maintain for each Regulation Zone an amount of Regulation equal to the Regulation objective for such Regulation Zone as specified in the PJM Manuals.

(c) The Regulation range of a generation unit or Demand Resource shall be at least twice the amount of Regulation assigned as described in the PJM Manuals.

(d) A resource capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced by at least twice the amount of the Regulation provided with consideration of the Regulation limits of that resource, as specified in the PJM Manuals.

(e) Qualified Regulation must satisfy the measurement and verification tests described in the PJM Manuals.

1.7.19 Ramping.

A generator dispatched by the Office of the Interconnection pursuant to a control signal appropriate to increase or decrease the generator's megawatt output level shall be able to change output at the ramping rate specified in the Offer Data submitted to the Office of the Interconnection for that generator.

1.7.19A Synchronized Reserve.

(a) Synchronized Reserve shall be supplied from generation resources and/or Demand Resources located within the metered boundaries of the PJM Region. Generating Market Buyers, and Market Sellers offering Synchronized Reserve shall comply with applicable standards and requirements for Synchronized Reserve capability and dispatch specified in the PJM Manuals

(b) The Office of the Interconnection shall obtain and maintain for each Synchronized Reserve Zone an amount of Synchronized Reserve equal to the Synchronized Reserve objective for such Synchronized Reserve Zone, as specified in the PJM Manuals.

(c) The Synchronized Reserve capability of a generation resource and Demand Resource shall be the increase in energy output or load reduction achievable by the generation resource and Demand Resource within a continuous 10-minute period.

(d) A generation unit capable of automatic energy dispatch that also is providing Synchronized Reserve shall have its energy dispatch range reduced by the amount of the Synchronized Reserve provided. The amount of Synchronized Reserve provided by a generation unit shall serve to redefine the Normal Maximum Generation energy limit of that generation unit in that the amount of Synchronized Reserve provided shall be subtracted from its Normal Maximum Generation energy limit.

1.7.19B Bilateral Transactions Regarding Regulation, Synchronized Reserve and Day-ahead Scheduling Reserves.

(a) In addition to transactions in the Regulation market, Synchronized Reserve market, and Day-ahead Scheduling Reserves Market, Market Participants may enter into bilateral contracts for the purchase or sale of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from each other or any other entity. Such bilateral contracts shall be for the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its eMarket tools.

(b) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to a Market Participant in the PJM Region, title to the product that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and any further transactions associated with such products or further sale of such Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves in the markets for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves, respectively, shall be transacted by the buyer under the bilateral contract. In no event shall the purchase and sale of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves between Market Participants under a bilateral contract constitute a transaction in PJM's markets for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves, or otherwise be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

(c) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the amounts of such reported transactions to amounts reflecting the expected requirements for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves of the buyer pursuant to such bilateral contracts.

(d) All payments and related charges for the Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by 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 a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

(e) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any purchases by the seller under the bilateral contract in the markets for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves used to meet the bilateral contract seller's obligation to deliver Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new eMarket reporting by the Market Participant and (ii) terminate all of the Market Participant's reporting of eMarkets schedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the reported eMarkets schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection.

(f) Market Participants shall purchase Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves from PJM's markets for Regulation, Synchronized Reserve, Day-ahead Scheduling Reserves, in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason, with respect to all bilateral transactions that contemplate the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from a Market Participant.

1.7.20 Communication and Operating Requirements.

(a) Market Participants. Each Market Participant shall have, or shall arrange to have, its transactions in the PJM Interchange Energy Market subject to control by a Market Operations Center, with staffing and communications systems capable of real-time communication with the Office of the Interconnection during normal and Emergency conditions and of control of the Market Participant's relevant load or facilities sufficient to meet the requirements of the Market Participant's transactions with the PJM Interchange Energy Market, including but not limited to the following requirements as applicable.

(b) Market Sellers selling from generation resources and/or Demand Resources within the PJM Region shall: report to the Office of the Interconnection sources of energy available for operation; supply to the Office of the Interconnection all applicable Offer Data; report to the Office of the Interconnection generation resources and Demand Resources that are self-scheduled; with respect to generation resources, report to the Office of the Interconnection bilateral sales transactions to buyers not within the PJM Region; confirm to the Office of the Interconnection bilateral sales to Market Buyers within the PJM Region; respond to the Office of the Interconnection's directives to start, shutdown or change output levels of generation units, or change scheduled voltages or reactive output levels of generation units, or reduce load from Demand Resources; continuously maintain all Offer Data concurrent with on-line operating

information; and ensure that, where so equipped, generating equipment and Demand Resources are operated with control equipment functioning as specified in the PJM Manuals.

(c) Market Sellers selling from generation resources outside the PJM Region shall: provide to the Office of the Interconnection all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to Office of the Interconnection directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the Market Seller's Control Area.

(d) Market Participants that are Load Serving Entities or purchasing on behalf of Load Serving Entities shall: respond to Office of the Interconnection directives for load management steps; report to the Office of the Interconnection Generation Capacity Resources to satisfy capacity obligations that are available for pool operation; report to the Office of the Interconnection all bilateral purchase transactions; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(e) Market Participants that are not Load Serving Entities or purchasing on behalf of Load Serving Entities shall: provide to the Office of the Interconnection requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the PJM Interchange Energy Market, along with Dispatch Rate levels above which it does not desire to purchase; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(f) Economic Load Response Participants are responsible for maintaining demand reduction information, including the amount and price at which demand may be reduced. The Economic Load Response Participant shall provide this information to the Office of the Interconnection by posting it on the Load Response Program Registration link of the PJM website as required by the PJM Manuals. The Economic Load Response Participant shall notify the Office of the Interconnection of a demand reduction concurrent with, or prior to, the beginning of such demand reduction in accordance with the PJM Manuals. In the event that an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer that would affect a relevant Customer Baseline Load as required by the PJM Manuals.

(g) PRD Providers shall be responsible for ensuring automated reductions to their Price Responsive Demand in response to price in accordance with their PRD Curves submitted to the Office of the Interconnection.

1.10 Scheduling.

1.10.1 General.

(a) The Office of the Interconnection shall administer scheduling processes to implement a Day-ahead Energy Market and a Real-time Energy Market. PJMSettlement shall be the Counterparty to the purchases and sales of energy that clear the Day-ahead Energy Market and the Real-time Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a Generating Market Buyer's self-schedule or self-supply of its generation resources up to that Generating Market Buyer's Equivalent Load.

(b) The Day-ahead Energy Market shall enable Market Participants to purchase and sell energy through the PJM Interchange Energy Market at Day-ahead Prices and enable Transmission Customers to reserve transmission service with Transmission Congestion Charges and Transmission Loss Charges based on locational differences in Day-ahead Prices. Up-To Congestion transactions submitted in the Day-ahead Energy Market shall not require transmission service and Transmission Customers shall not reserve transmission service for such transactions. Market Participants whose purchases and sales, and Transmission Customers whose transmission uses are scheduled in the Day-ahead Energy Market, shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, at the applicable Day-ahead Prices for the amounts scheduled.

(c) In the Real-time Energy Market, Market Participants that deviate from the amounts of energy purchases or sales, or Transmission Customers that deviate from the transmission uses, scheduled in the Day-ahead Energy Market shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling shall be conducted as specified below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up

times greater than one day as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM Manuals.

1.10.1A Day-Ahead Energy Market Scheduling.

The following actions shall occur not later than 12:00 noon on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the Office of the Interconnection in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Schedule.

(a) Each Market Participant may submit to the Office of the Interconnection specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the PJM Manuals. Each Market Buyer shall inform the Office of the Interconnection of the prices, if any, at which it desires not to include its load in the Day-ahead Energy Market rather than pay the Day-ahead Price. PRD Providers that have committed Price Responsive Demand in accordance with the Reliability Assurance Agreement shall submit to the Office of the Interconnection, in accordance with procedures specified in the PJM Manuals, any desired updates to their previously submitted PRD Curves, provided that such updates are consistent with their Price Responsive Demand commitments, and provided further that PRD Providers that are not Load-Serving Entities for the Price Responsive Demand load at issue may only submit PRD Curves for the Real-time Energy Market. Price Responsive Demand that has been committed in accordance with the Reliability Assurance Agreement shall be presumed available for the next Operating Day in accordance with the most recently submitted PRD Curve unless the PRD Curve is updated to indicate otherwise. PRD Providers may also submit PRD Curves for any Price Responsive Demand that is not committed in accordance with the Reliability Assurance Agreement; provided that PRD Providers that are not Load-Serving Entities for the Price Responsive Demand load at issue may only submit PRD Curves for the Real-time Energy Market. All PRD Curves shall be on a PRD Substation basis, and shall specify the maximum time period required to implement load reductions.

(b) Each Generating Market Buyer shall submit to the Office of the Interconnection: (i) hourly schedules for resource increments, including hydropower units, self-scheduled by the Market Buyer to meet its Equivalent Load; and (ii) the Dispatch Rate at which each such self-scheduled resource will disconnect or reduce output, or confirmation of the Market Buyer's intent not to reduce output.

(c) All Market Participants shall submit to the Office of the Interconnection schedules for any bilateral transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection whether the transaction is to be included in the Day-ahead Energy Market. Any Market Participant that elects to include a bilateral transaction in the Day-ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the PJM Manuals), if any, at which it will be

wholly or partially curtailed rather than pay Transmission Congestion Charges. The foregoing price specification shall apply to the price difference between the specified bilateral transaction source and sink points in the day-ahead scheduling process only. Any Market Participant that elects not to include its bilateral transaction in the Day-ahead Energy Market shall inform the Office of the Interconnection if the parties to the transaction are not willing to incur Transmission Congestion Charges in the Real-time Energy Market in order to complete any such scheduled bilateral transaction. Scheduling of bilateral transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

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

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

iii) In addition to the foregoing schedules for bilateral transactions, Market Participants shall submit confirmations of each scheduled bilateral transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(d) Market Sellers wishing to sell into the Day-ahead Energy Market shall submit offers for the supply of energy (including energy from hydropower units), demand reductions, Regulation, Operating Reserves or other services for the following Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Attachment DD of the PJM Tariff, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. The submission of offers for resource increments that have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, and PJM Manuals, as applicable. Energy offered from generation resources that have not cleared a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region. The foregoing offers:

i) Shall specify the Generation Capacity Resource or Demand Resource and energy or demand reduction amount, respectively, for each hour in the offer period, and the minimum run time for generation resources and minimum down time for Demand Resources;

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

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

iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;

v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with a second schedule applicable if accepted after the foregoing deadline;

vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer, which offer shall remain open through the Operating Day for which the offer is submitted;

vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day; and

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

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation that shall specify the megawatt of Regulation being offered, which must equal or exceed 0.1 megawatts, the Regulation Zone for which such regulation is offered, the price of the capability offer in dollars per MW, the price of the performance offer in Dollars per change in MW, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the resource's opportunity costs. The total of the performance offer multiplied by the historical average mileage used in the market clearing plus the capability offer shall not exceed $100 per MWh in the case of Regulation offered for all Regulation Zones. In addition to any market-based offer for Regulation, the Market Seller also shall submit a cost-based offer. A cost-based offer must be in the form specified in the PJM Manuals and consist of the following components as well as any other components specified in the PJM Manuals:

i. The costs (in $/MW) of the fuel cost increase due to the heat rate increase resulting from operating a unit at lower megawatt output incurred from the provision of Regulation;

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

iii. An adder of up to $12.00 per megawatt of Regulation provided applied to the capability offer.

Qualified Regulation capability must satisfy the measurement and verification tests specified in the PJM Manuals.

(f) Each Market Seller owning or controlling the output of a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative shall submit a forecast of the availability of each such Generation Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with start-up and no-load fees, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours.

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

(h) The Office of the Interconnection shall post the total hourly loads scheduled in the Day-ahead Energy Market, as well as, its estimate of the combined hourly load of the Market Buyers for the next four days, and peak load forecasts for an additional three days.

(i) Except for Economic Load Response Participants, all Market Participants may submit Increment Bids and/or Decrement Bids that apply to the Day-ahead Energy Market only. Such bids must comply with the requirements set forth in the PJM Manuals and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-ahead Energy Market. The Office of the Interconnection may require that a market participant shall not submit in excess of 3000 bid/offer segments in the Day-ahead Energy Market, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to 10:00 a.m. EPT on the day that the Day-ahead Energy Market will clear. For purposes of this provision, a bid/offer segment is each pairing of price and megawatt quantity submitted as part of an Increment Bid or Decrement Bid.

(j) A Market Seller that wishes to make a generation resource or Demand Resource available to sell Synchronized Reserve shall submit an offer for Synchronized Reserve that shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.1

megawatts, the price of the offer in dollars per megawatt hour, and such other information specified by the Office of Interconnection as may be necessary to evaluate the offer and the energy used by the generation resource to provide the Synchronized Reserve and the generation resource's unit specific opportunity costs. The price of the offer shall not exceed the variable operating and maintenance costs for providing Synchronized Reserve plus seven dollars and fifty cents.

(k) An Economic Load Response Participant that wishes to participate in the Day-ahead Energy Market by reducing demand shall submit an offer to reduce demand to the Office of the Interconnection. The offer must equal or exceed 0.1 megawatts, and the offer shall specify: (i) the amount of the offered curtailment in minimum increments of .1 megawatts: (ii) the Day-ahead Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, start-up costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum of number of contiguous hours for which the load reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs).

(l) Market Sellers owning or controlling the output of a Demand Resource that was committed in an FRR Capacity Plan, self-supplied or offered and cleared in the Base Residual Auction or one of the Incremental Auctions, or owning or controlling the output of an ILR resource which was certified as specified in Attachment DD of the PJM Tariff, may submit demand reduction bids for the available load reduction capability of the Demand Resource or ILR resource. The submission of demand reduction bids for resource increments that have not cleared in the Base Residual Auction or in one of the Incremental Auctions, or for ILR resources that were not certified, or were not committed in an FRR Capacity Plan, shall be optional, but any such bids must contain the information specified in the PJM Economic Load Response Program to be included in such bids. A Demand Resource that was committed in an FRR Capacity plan, self-supplied or offered and cleared in a Base Residual Auction or an Incremental Auction may submit a demand reduction bid in the Day-ahead Energy Market as specified in the Economic Load Response Program, provided however, that in the event of an Emergency, PJM shall require Demand Resources and ILR resources to reduce load notwithstanding that the Zonal LMP at the time such Emergency is declared is below the price identified in the demand reduction bid.

(m) Market Sellers that wish to make Day-ahead Scheduling Reserves Resources available to sell Day-ahead Scheduling Reserves shall submit offers, each of which must equal or exceed 0.1 megawatts, in the Day-ahead Scheduling Reserves Market specifying: 1) the price of the offer in dollars per megawatt hour; and 2) such other information specified by the Office of the Interconnection as may be necessary to determine any relevant opportunity costs for the resource(s). The foregoing notwithstanding, to qualify to submit offers pursuant to this section, the Day-ahead Scheduling Reserves Resources shall submit energy offers in the Day-ahead Energy Market including start-up and shut-down costs for generation resource and Demand Resources, respectively, and all generation resources that are capable of providing Day-ahead Scheduling Reserves that a particular resource can provide that service. The MW quantity of

Day-Ahead Scheduling Reserves that a particular resource can provide in a given hour will be determined based on the energy Offer Data submitted in the Day-ahead Energy Market, as detailed in the PJM Manuals.

1.10.2 Pool-Scheduled Resources.

Pool-scheduled resources are those resources for which Market Participants submitted offers to sell energy in the Day-ahead Energy Market and offers to reduce demand in the Day-ahead Energy Market, which the Office of the Interconnection scheduled in the Day-ahead Energy Market as well as generators committed by the Office of the Interconnection subsequent to the Day-ahead Energy Market. Such resources shall be committed to provide energy in the real-time dispatch unless the schedules for such units are revised pursuant to Sections 1.10.9 or 1.11. Pool-scheduled resources shall be governed by the following principles and procedures.

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, start-up, no-load and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in Section 1.10.1A.

(b) A resource that is scheduled by a Market Participant to support a bilateral sale, or that is self-scheduled by a Generating Market Buyer, shall not be selected by the Office of the Interconnection as a pool-scheduled resource except in an Emergency.

(c) Market Sellers offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the Office of the Interconnection that is sufficient to enable the Office of the Interconnection to determine the available operating hours of such facilities.

(d) The Market Seller of a resource selected as a pool-scheduled resource shall receive payments or credits for energy, demand reductions or related services, or for start-up and no-load fees, from the Office of the Interconnection on behalf of the Market Buyers in accordance with Section 3 of this Schedule 1. Alternatively, the Market Seller shall receive, in lieu of start-up and no-load fees, its actual costs incurred, if any, up to a cap of the resource's start-up cost, if the Office of the Interconnection cancels its selection of the resource as a pool-scheduled resource and so notifies the Market Seller before the resource is synchronized.

(e) Market Participants shall make available their pool-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone.

(f) Economic Load Response Participants offering to reduce demand shall specify: (i) the amount of the offered curtailment, which offer must equal or exceed 0.1 megawatts, in minimum increments of .1 megawatts; (ii) the real-time Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, shut-down costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum number of contiguous hours for which the load

reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Real-time Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs). Economic Load Response Participants offering to reduce demand shall also indicate the hours that the demand reduction is not available.

1.10.3 Self-scheduled Resources.

Self-scheduled resources shall be governed by the following principles and procedures.

(a) Each Generating Market Buyer shall use all reasonable efforts, consistent with Good Utility Practice, not to self-schedule resources in excess of its Equivalent Load.

(b) The offered prices of resources that are self-scheduled, or otherwise not following the dispatch orders of the Office of the Interconnection, shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.

(c) Market Participants shall make available their self-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone, by submitting an offer as to such resources.

(d) A Market Participant self-scheduling a resource in the Day-ahead Energy Market that does not deliver the energy in the Real-time Energy Market, shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

1.10.4 Capacity Resources.

(a) A Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that is selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection. Such a Generation Capacity Resource that does not deliver energy as scheduled shall be deemed to have experienced a Generator Forced Outage to the extent of such energy not delivered. A Market Participant offering such Generation Capacity Resource in the Day-ahead Energy Market shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Energy from a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that has not been scheduled in the Day-ahead Energy Market may be sold on a bilateral basis by the Market Seller, may be self-scheduled, or may be offered for dispatch during the Operating Day in accordance with the procedures specified in this Schedule. Such a Generation Capacity Resource that has not been scheduled in the Day-ahead Energy Market and that has been sold on a bilateral basis must be made available upon request to the Office of the Interconnection for scheduling and dispatch during the Operating Day if the

Office of the Interconnection declares a Maximum Generation Emergency. Any such resource so scheduled and dispatched shall receive the applicable Real-time Price for energy delivered.

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

1.10.5 External Resources.

(a) External Resources may submit offers to the PJM Interchange Energy Market, in accordance with the day-ahead and real-time scheduling processes specified above. An External Resource selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection, and except as specified below shall be compensated on the same basis as other pool-scheduled resources. External Resources that are not capable of dynamic dispatch shall, if selected by the Office of the Interconnection on the basis of the Market Seller's Offer Data, be block loaded on an hourly scheduled basis. Market Sellers shall offer External Resources to the PJM Interchange Energy Market on either a resource-specific or an aggregated resource basis. A Market Participant whose pool-scheduled resource does not deliver the energy scheduled in the Day-ahead Energy Market shall replace such energy not delivered as scheduled in the Day-ahead Energy Market with energy from the PJM Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Offers for External Resources from an aggregation of two or more generating units shall so indicate, and shall specify, in accordance with the Offer Data requirements specified by the Office of the Interconnection: (i) energy prices; (ii) hours of energy availability; (iii) a minimum dispatch level; (iv) a maximum dispatch level; and (v) unless such information has previously been made available to the Office of the Interconnection, sufficient information, as specified in the PJM Manuals, to enable the Office of the Interconnection to model the flow into the PJM Region of any energy from the External Resources scheduled in accordance with the Offer Data.

(c) Offers for External Resources on a resource-specific basis shall specify the resource being offered, along with the information specified in the Offer Data as applicable.

1.10.6 External Market Buyers.

(a) Deliveries to an External Market Buyer not subject to dynamic dispatch by the Office of the Interconnection shall be delivered on a block loaded basis to the bus or busses at the electrical boundaries of the PJM Region, or in such area with respect to an External Market Buyer's load within such area not served by Network Service, at which the energy is delivered to or for the External Market Buyer. External Market Buyers shall be charged (which charge may be positive or negative) at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing bus or busses.

(b) An External Market Buyer's hourly schedules for energy purchased from the PJM Interchange Energy Market shall conform to the ramping and other applicable requirements of

the interconnection agreement between the PJM Region and the Control Area to which, whether as an intermediate or final point of delivery, the purchased energy will initially be delivered.

(c) The Office of the Interconnection shall curtail deliveries to an External Market Buyer if necessary to maintain appropriate reserve levels for a Control Zone as defined in the PJM Manuals, or to avoid shedding load in such Control Zone.

1.10.6A Transmission Loading Relief Customers.

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

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

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

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

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

1.10.7 Bilateral Transactions.

Bilateral transactions as to which the parties have notified the Office of the Interconnection by the deadline specified in Section 1.10.1A that they elect not to be included in the Day-ahead Energy Market and that they are not willing to incur Transmission Congestion Charges in the Real-time Energy Market shall be curtailed by the Office of the Interconnection as necessary to reduce or alleviate transmission congestion. Bilateral transactions that were not included in the Day-ahead Energy Market and that are willing to incur congestion charges and bilateral transactions that were accepted in the Day-ahead Energy Market shall continue to be implemented during periods of congestion, except as may be necessary to respond to Emergencies.

1.10.8 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers and PRD Curves properly submitted by Load Serving Entities for the Price Responsive Demand loads they serve; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv) the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) Not earlier than 4:00 p.m. of the day before each Operating Day, or such other deadline as may be specified by the Office of the Interconnection in the PJM Manuals, the Office of the Interconnection shall: (i) post the aggregate Day-ahead Energy Market results; (ii) post the Day-ahead Prices; and (iii) inform the Market Sellers, Market Buyers, and Economic Load Response Participants of their scheduled injections, withdrawals, and demand reductions respectively.

(c) Following posting of the information specified in Section 1.10.8(b), the Office of the Interconnection shall revise its schedule of generation resources to reflect updated projections of load, conditions affecting electric system operations in the PJM Region, the availability of and constraints on limited energy and other resources, transmission constraints, and other relevant factors.

(d) Market Buyers shall pay PJMSettlement and Market Sellers shall be paid by PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the offer that set the Day-ahead Price is positive. Market Buyers shall be paid by PJMSettlement and Market Sellers shall pay PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the offer that set the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Section 3.3A of this Schedule.

(e) If the Office of the Interconnection discovers an error in prices and/or cleared quantities in the Day-ahead Energy Market, Real-time Energy Market, Ancillary Services Markets or Day Ahead Scheduling Reserve Market after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 12:00 p.m. of the second business day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the second business day following the initial publication of the results for the Day-ahead Scheduling Reserve Market and Day-ahead Energy Market.

After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the fifth business day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the fifth business day following the initial publication of the results in the Day-ahead Scheduling Reserve Market and the Day-ahead Energy Market. Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating Day for the Ancillary Services Markets, Day-ahead Energy Market and Real-time Energy Market, and no later than 5:00 p.m. of the tenth calendar day following the initial publication of the results in the Day-ahead Scheduling Reserve Market. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced market results are under publicly noticed review by the FERC.

(f) Consistent with Section 18.17.1 of the PJM Operating Agreement, and notwithstanding anything to the contrary in the Operating Agreement or in the PJM Tariff, to allow the tracking of Market Participants' non-aggregated bids and offers over time as required by FERC Order No. 719, the Office of the Interconnection shall post on its Web site the non-aggregated bid data and Offer Data submitted by Market Participants (for participation in the PJM Interchange Energy Market) approximately four months after the bid or offer was submitted to the Office of the Interconnection.

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, a generation rebidding period shall exist from 4:00 p.m. to 6:00 p.m. on the day before each Operating Day. During the rebidding period, Market Participants may submit revisions to generation Offer Data for any generation resource that was not selected as a pool-scheduled resource in the Day-ahead Energy Market. Adjustments to Day-ahead Energy Markets shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 60 minutes prior to the hour in which the adjustment is to take effect, as follows:

i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;

ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or

iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or

iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any start-up fee.

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

(d) An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase in the Day-ahead Energy Market by notifying the Office of the Interconnection of the adjustment in deliveries not later than 60 minutes prior to the hour in which the adjustment is to take effect, but any such adjustment shall not affect the obligation of the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(e) For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section 1.10, the Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules for the hour.

1.11 Dispatch.

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

1.11.1 Resource Output.

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

1.11.2 Operating Basis.

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

1.11.3 Pool-dispatched Resources.

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

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

1.11.3A Maximum Generation Emergency.

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

1.11.4 Regulation.

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

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

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

1.11.4A Synchronized Reserve.

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

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

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

1.11.5 PJM Open Access Same-time Information System.

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

2.2 General.

The Office of the Interconnection shall determine the least cost security-constrained dispatch, which is the least costly means of serving load and meeting reserve requirements at different locations in the PJM Region based on actual operating conditions existing on the power grid (including transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6) and on the prices at which Market Sellers have offered to supply energy and offers by Economic Load Response Participants to reduce demand that qualify to set Locational Marginal Prices in the PJM Interchange Energy Market. Locational Marginal Prices for the generation and load busses in the PJM Region, including interconnections with other Control Areas, will be calculated based on the actual economic dispatch and the prices of energy and demand reduction offers. The process for the determination of Locational Marginal Prices shall be as follows:

(a) To determine actual operating conditions on the power grid in the PJM Region, the Office of the Interconnection shall use a computer model of the interconnected grid that uses available metered inputs regarding generator output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network. The computer model employed for this purpose, referred to as the State Estimator program, is a standard industry tool and is described in Section 2.3 below. It will be used to obtain information regarding the output of generation supplying energy to the PJM Region, loads at busses in the PJM Region, transmission losses, and power flows on binding transmission constraints for use in the calculation of Locational Marginal Prices. Additional information used in the calculation, including Dispatch Rates and real time schedules for external transactions between PJM and other Control Areas and dispatch and pricing information from entities with whom PJM has executed a joint operating agreement, will be obtained from the Office of the Interconnection's dispatchers.

(b) Using the prices at which energy is offered by Market Sellers and demand reductions are offered by Economic Load Response Participants to the PJM Interchange Energy Market, the Office of the Interconnection shall determine the offers of energy and demand reductions that will be considered in the calculation of Locational Marginal Prices. As described in Section 2.4 below, every qualified offer for demand reduction and of energy by a Market Seller from resources that are following economic dispatch instructions of the Office of the Interconnection will be utilized in the calculation of Locational Marginal Prices, including, without limitation, qualified offers from Economic Load Response Participants in either the Day-Ahead or Real-Time Energy Markets that satisfy the Net Benefits Test. Offers of demand reduction from Demand Resources in the Real-time Energy Market will not be eligible to set Locational Marginal Prices, unless metered directly by the Office of the Interconnection.

(c) Based on the system conditions on the PJM power grid, determined as described in (a), and the eligible energy and demand reduction offers, determined as described in (b), the Office of the Interconnection shall determine the least costly means of obtaining energy to serve

the next increment of load at each bus in the PJM Region, in the manner described in Section 2.5 below. The result of that calculation shall be a set of Locational Marginal Prices based on the system conditions at the time.

2.3 Determination of System Conditions Using the State Estimator.

Power system operations, including, but not limited to, the determination of the least costly means of serving load and meeting reserve requirements, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In calculating Locational Marginal Prices, the Office of the Interconnection shall obtain a complete and consistent description of conditions on the electric network in the PJM Region by using the most recent power flow solution produced by the State Estimator program and utilized in the PJM dispatch algorithm, which State Estimator program is also used by the Office of the Interconnection for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available real-time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at busses for which real-time information is unavailable. The Office of the Interconnection shall obtain a State Estimator solution every five minutes, which shall provide the megawatt output of generators and the loads at busses in the PJM Region, transmission line losses, and actual flows or loadings on constrained transmission facilities. External transactions between PJM and other Control Areas shall be included in the Locational Marginal Price calculation on the basis of the real time transaction schedules implemented by the Office of the Interconnection's dispatcher.

2.5 Calculation of Real-time Prices.

(a) The Office of the Interconnection shall determine the least costly means of obtaining energy to serve the next increment of load (taking account of any applicable and available load reductions indicated on PRD Curves properly submitted by any PRD Provider) at each bus in the PJM Region represented in the State Estimator and each Interface Pricing Point between PJM and an adjacent Control Area, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and utilized in the PJM dispatch algorithm and the energy offers that are the basis for the Day-ahead Energy Market, or that are determined to be eligible for consideration under Section 2.4 in connection with the real-time dispatch, as applicable. This calculation shall be made by applying a real-time joint optimization of energy and reserves, given actual system conditions, a set of energy offers, a set of reserve offers, a set of Reserve Penalty Factors, and any binding transmission constraints that may exist. In performing this calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a generation resource or decrease an increment of energy being consumed by a Demand Resource, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses. The real-time Locational Marginal Prices at a bus shall be determined through the joint optimization based on the lowest marginal cost to serve the next increment of load at the bus taking into account the applicable reserve requirements, unit resource constraints, transmission constraints and marginal loss impact.

(b) If PJM is able to meet its Synchronized Reserve requirements as specified in 1.7.19A, real-time Locational Marginal Prices shall be calculated as described in Section 2.5(a) above. When Synchronized Reserve requirements cannot be met, the real-time Locational Marginal Prices shall be calculated in accordance with 2.5(a) above and Section 6A of this Schedule 1.

(c) During the Operating Day, the calculation set forth in (a) shall be performed every five minutes, using the Office of the Interconnection's Locational Marginal Price program, producing a set of Real-time Prices based on system conditions during the preceding interval. The prices produced at five-minute intervals during an hour will be integrated to determine the Real-time Prices for that hour.

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 (g) of this section; the amounts, if any, described in subsection (e) of this section; and (iii) the Internal Market Buyer's pro rata share of any performance credits paid to regulating resources calculated in accordance with subsection (f) 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 such that the calculated credit for each increment of Regulation provided by each resource shall be the Regulation market-clearing price.

(c) If PJM is able to meet its Synchronized Reserve requirements as specified in 1.7.19A, 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 (f) 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 from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.3.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation 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 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.

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

(e) 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.

(f) 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 expected amount of Regulation that resource will be dispatched based on the historical ratio of control signals calculated by the Office of the Interconnection, and the ratio of benefits to system control for following the Regulation control signal 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 based on the assigned MW(s), the performance Regulation market-clearing price, the amount of Regulation performance of the resource provides during the market hour, and the accuracy with which each resource responds to the Office of the Interconnection's Regulation signals during the market hour.

(g) 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 (f) 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 capacity Regulation market-clearing price.

(h) 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.

(i) If PJM is unable to meet its Synchronized Reserve requirements as specified in 1.7.19A, the performance Regulation clearing price and the capability Regulation clearing price will be held steady for the duration of the reserve deficiency at the last value calculated prior to the start of the reserve deficiency. In the event of such reserve deficiency, 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 at the higher of (i) the Regulation market-clearing price in such Regulation Zone or (ii) the sum of the regulation offer and the unit-specific opportunity cost of the generation resource supplying the increment of Regulation.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to section 1.10.1A(e) of this Schedule. A Regulation supplier fails the three-pivotal supplier test in any hour in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

(b) For the purposes of conducting the three-pivotal supplier test pursuant to this section, the following applies:

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region for which the 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.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Section 3.2.3A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10

of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the Day-ahead Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load fees and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve credits, identified as RA Credits for Reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

(c) The sum of the foregoing credits calculated in accordance with Section 3.2.3(b) plus any unallocated charges from Section 3.2.3(h) and 5.1.7 and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of Operating Reserves in the Day-ahead Energy Market.

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following segments: 1) the greater of

their day-ahead schedules or minimum run time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or minimum run time (minimum down time for Demand Resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time (minimum down time for Demand Resources) and Segment 2 will include the remainder of the contiguous hours when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

Credits received pursuant to this section shall be equal to the positive difference between a resource's total offered price for start-up (shutdown costs for Demand Resources) and no-load fees and energy, determined on the basis of the resource's scheduled output, and the total value of the resource's energy as determined by the Real-time Energy Market and the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for segment 2 shall exclude start up (shutdown costs for Demand Resources) costs for generation resources.

Except as provided in Section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to Section 3.2.3(b) plus the resource's opportunity cost and less any amounts credited for Synchronized Reserve in excess of the Synchronized Reserve offer plus the resource's opportunity cost and less any amounts credited for Reactive Services as specified in Section 3.2.3.B, and less any amounts for Day-ahead Scheduling Reserve in excess of the Day-ahead Scheduling Reserve offer plus the resource's opportunity cost, shall be credited to the Market Seller.

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

(f) A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding

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

AG equals the actual hourly integrated output of the unit;

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

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

where URTLMP - UB shall not be negative.

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

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described above for a steam unit or combined cycle unit operating in combined cycle mode.

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

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

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

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

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

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

(f-2) A Market Seller's hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Section 1.10.2(d) such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves, plus any redispatch costs incurred in accordance with section 10(a) of this Schedule, shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (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 area pursuant to Section 1.12.

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

The foregoing notwithstanding, netting deviations shall be allowed in accordance with the following provisions:

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of an Operating Reserve shortage in real-time or where PJM initiates the request for load reductions in real-time in order to avoid an Operating Reserve shortage as described in this Schedule, Section 6A, Scarcity Pricing.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in Section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for of the PJM Region.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-

contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside the PJM Region pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared ("Maximum Generation Emergency Alert"); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the Operating Reserves credit otherwise provided by Section 3.2.3.(b) or Section 3.2.3(e) in connection with market-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as "MaxGen Conditions"). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Schedule 2 of the Operating Agreement, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatt hours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any hours required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon on the day before the Operating Day for which transactions are being

scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described in the PJM Manuals. Ramp-limited desired MW values shall be used to determine generation resource real-time deviations from the resource's day-ahead schedules.

The Office of the Interconnection shall calculate a ramp-limited desired MW value for generation resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:

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

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

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

$$RL_Desired_t = AOutput_{t-1} + \left(Ramp_Request_t * Case_Eff_time_{t-1} \right)$$

where:

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

To determine if a 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 <= 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 n 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 to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve charges shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve charges shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve charges shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be

identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region. For the purposes of this section, the Western Region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, DEOK transmission Zones, and the Eastern Region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones. The regional balancing Operating Reserve rates shall be determined in accordance with the following provisions:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

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

(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.

3.2.3A Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Synchronized Reserve Zone of the PJM Region, based on the

Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Synchronized Reserve Zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). An Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts if any, described in subsections (g), (h) and (i) of this section.

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

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

ii) Credits for Synchronized Reserve provided by generation resources that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the Interconnection energy dispatch signals and instructions ("Tier 2 Synchronized Reserve") shall be the higher of (i) the Synchronized Reserve Market Clearing Price or (ii) the sum of (A) the Synchronized Reserve offer, and (B) the specific opportunity cost of the generation resource supplying the increment of Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

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

(c) The Synchronized Reserve Energy Premium Price is the average of the five-minute Locational Marginal Prices calculated during the Synchronized Reserve Event plus an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Synchronized Reserve Zone by the Office of the Interconnection prior to the operating hour and such market-clearing price shall be equal to, from among the generation resources or Demand

Resources selected to provide Synchronized Reserve for such Synchronized Reserve Zone, the highest sum of either (i) a generation resource's Synchronized Reserve offer and opportunity cost or (ii) a demand response resource's Synchronized Reserve offer.

(e) In determining the 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 expected Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

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

(g) Charges for Tier 1 Synchronized Reserve will be allocated in proportion to the amount of Tier 1 Synchronized Reserve applied to each Synchronized Reserve Obligation. In the event Tier 1 Synchronized Reserve is provided by a Market Seller in excess of that Market Seller's Synchronized Reserve Obligation, the remainder of the Tier 1 Synchronized Reserve that is not utilized to fulfill the Seller's obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

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

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

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

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l) is the difference between the generation resource's output or the Demand Resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load Demand Resource's consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Demand Resource's

consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.

(m) If PJM is unable to meet its Synchronized Reserve requirements as specified in 1.7.19A, the Synchronized Reserve Market Clearing Price will be held steady for the duration of the reserve deficiency at the last value calculated prior to the start of the reserve deficiency.

3.2.3A.01 Day-ahead Scheduling Reserves.

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

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

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

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

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

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

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

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

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

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

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

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit hourly in an amount equal to {(LMPDMW - AG) x (URTLMP - UB)}

where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

AG equals the actual hourly integrated output of the unit;

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

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

where URTLMP - UB shall not be negative.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

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

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

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

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

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

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

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to Section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit hourly in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual hourly integrated output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

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

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

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's hourly cost to provide synchronous condensing, calculated in

accordance with the PJM Manuals, (B) the hourly product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generating unit's bus, (C) the generating unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generating resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generating unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to paragraph (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the

Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers

counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to section (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

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

3.2.5 Transmission Loss Charges.

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

3.2.6 Emergency Energy.

(a) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each hour of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(b) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each hour of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(c) The net costs or net revenues associated with sales or purchases of hourly energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each hour of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Buyer in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market Buyer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Buyer's internal accounting.

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

Definitions Q - R

1.38.01 Regional RTEP Project.

"Regional RTEP Project" shall mean a transmission expansion or enhancement rated at 230 kV or above which is required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.

1.38.01A Relevant Electric Retail Regulatory Authority:

An entity that has jurisdiction over and establishes prices and policies for competition for providers of retail electric service to end-customers, such as the city council for a municipal utility, the governing board of a cooperative utility, the state public utility commission or any other such entity.

1.38A Regulation Zone.

"Regulation Zone" shall mean any of those one or more geographic areas, each consisting of a combination of one or more Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirements for, regulation service.

1.39 Related Parties.

"Related Parties" shall mean, solely for purposes of the governance provisions of this Agreement: (i) any generation and transmission cooperative and one of its distribution cooperative members; and (ii) any joint municipal agency and one of its members. For purposes of this Agreement, representatives of state or federal government agencies shall not be deemed Related Parties with respect to each other, and a public body's regulatory authority, if any, over a Member shall not be deemed to make it a Related Party with respect to that Member.

1.40 Reliability Assurance Agreement.

"Reliability Assurance Agreement" shall mean that certain Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region, on file with FERC as PJM Interconnection, L.L.C. Rate Schedule FERC. No .42, establishing obligations, standards and procedures for maintaining the reliable operation of the PJM Region.

1.40A [Reserved].

1.40B [Reserved].

Definitions S – T

1.40C SERC.

"SERC" or "Southeastern Electric Reliability Council" shall mean the reliability council under section 202 of the Federal Power Act established pursuant to the SERC Agreement dated January 14, 1970, or any successor thereto.

1.41 Sector Votes.

"Sector Votes" shall mean the affirmative and negative votes of each sector of a Senior Standing Committee, as specified in Section 8.4.

1.41A Senior Standing Committees.

"Senior Standing Committees" shall mean the Members Committee, and the Markets, and Reliability Committee, as established in Sections 8.1 and 8.6.

1.41A.01 [Reserved].

1.41A.02 [Reserved].

1.41A.03 [Reserved].

1.41B Standing Committees.

"Standing Committees" shall mean the Members Committee, the committees established and maintained under Section 8.6, and such other committees as the Members Committee may establish and maintain from time to time.

1.42 State.

"State" shall mean the District of Columbia and any State or Commonwealth of the United States.

1.42.01 State Certification.

"State Certification" shall mean the Certification of an Authorized Commission, pursuant to Section 18 of this Agreement, the form of which is appended to this Agreement as Schedule 10A, wherein the Authorized Commission identifies all Authorized Persons employed or retained by such Authorized Commission, a copy of which shall be filed with FERC.

1.42A State Consumer Advocate.

"State Consumer Advocate" shall mean a legislatively created office from any State, all or any part of the territory of which is within the PJM Region, and the District of Columbia established, inter alia, for the purpose of representing the interests of energy consumers before the utility regulatory commissions of such states and the District of Columbia and the FERC.

1.42A.01 Subregional RTEP Project.

"Subregional RTEP Project" shall mean a transmission expansion or enhancement rated below 230 kV which is requiredfor compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.

1.42A.02 Supplemental Project.

"Supplemental Project" shall mean a Regional RTEP Project(s) or Subregional RTEP Project(s), which is not required for compliance with the following PJM criteria: System reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.

1.42B Synchronized Reserve Zone.

"Synchronized Reserve Zone" shall mean any of those geographic areas consisting of a combination of one or more of the Control Zone(s) as designated by the Office of the Interconnection in the PJM Manuals, relevant to provision of, and requirement for, Synchronized Reserve service.

1.43 System.

"System" shall mean the interconnected electric supply system of a Member and its interconnected subsidiaries exclusive of facilities which it may own or control outside of the PJM Region. Each Member may include in its system the electric supply systems of any party or parties other than Members which are within the PJM Region, provided its interconnection agreements with such other party or parties do not conflict with such inclusion.

1.43A Third Party Request.

"Third Party Request" shall mean any request or demand by any entity upon an Authorized Person or an Authorized Commission for release or disclosure of confidential information provided to the Authorized Person or Authorized Commission by the Office of the Interconnection or PJM Market Monitor. A Third Party Request shall include, but shall not be limited to, any subpoena, discovery request, or other request for confidential information made by any: (i) federal, state, or local governmental subdivision, department, official, agency or court, or (ii) arbitration panel, business, company, entity or individual.

1.44 Transmission Facilities.

"Transmission Facilities" shall mean facilities that: (i) are within the PJM Region; (ii) meet the definition of transmission facilities pursuant to FERC's Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and (iii) have been demonstrated to the satisfaction of the Office of the Interconnection to be integrated with the transmission system of the PJM Region and integrated into the planning and operation of such to serve all of the power and transmission customers within such region.

1.45 Transmission Owner.

"Transmission Owner" shall mean a Member that owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement. Taking transmission service shall not be sufficient to qualify a Member as a Transmission Owner.

1.46 [Reserved.]

1.3 Definitions.

1.3.1 Acceleration Request.

"Acceleration Request" shall mean a request pursuant to section 1.9.4A of this Schedule to accelerate or reschedule a transmission outage scheduled pursuant to sections 1.9.2 or 1.9.4.

1.3.1A Auction Revenue Rights.

"Auction Revenue Rights" or "ARRs" shall mean the right to receive the revenue from the Financial Transmission Right auction, as further described in Section 7.4 of this Schedule.

1.3.1B Auction Revenue Rights Credits.

"Auction Revenue Rights Credits" shall mean the allocated share of total FTR auction revenues or costs credited to each holder of Auction Revenue Rights, calculated and allocated as specified in Section 7.4.3 of this Schedule.

1.3.1B.01 Batch Load Demand Resource.

"Batch Load Demand Resource" shall mean a Demand Resource that has a cyclical production process such that at most times during the process it is consuming energy, but at consistent regular intervals, ordinarily for periods of less than ten minutes, it reduces its consumption of energy for its production processes to minimal or zero megawatts.

1.3.1B.02 Congestion Price.

"Congestion Price" shall mean the congestion component of the Locational Marginal Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.1B.03 Curtailment Service Provider.

"Curtailment Service Provider" or "CSP" shall mean a Member or a Special Member, which action on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market by causing a reduction in demand.

1.3.1B.04 Day-ahead Congestion Price.

"Day-ahead Congestion Price" shall mean the Congestion Price resulting from the Day-ahead Energy Market.

1.3.1C Day-ahead Energy Market.

"Day-ahead Energy Market" shall mean the schedule of commitments for the purchase or sale of energy and payment of Transmission Congestion Charges developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Section 1.10 of this Schedule.

1.3.1C.01 Day-ahead Loss Price.

"Day-ahead Loss Price" shall mean the Loss Price resulting from the Day-ahead Energy Market.

1.3.1D Day-ahead Prices.

"Day-ahead Prices" shall mean the Locational Marginal Prices resulting from the Day-ahead Energy Market.

1.3.1D.01 Day-ahead Scheduling Reserves.

"Day-ahead Scheduling Reserves" shall mean thirty-minute reserves as defined by the Reliability First Corporation and SERC.

1.3.1D.02 Day-ahead Scheduling Reserves Requirement.

"Day-ahead Scheduling Reserves Requirement" shall mean the thirty-minute reserve requirement for the PJM Region established consistent with Reliability First Corporation and SERC reliability standards, or those of any additional and/or successor regional reliability organization(s) that are responsible for establishing reliability requirements for the PJM Region, plus any additional thirty-minute reserves scheduled in response to an RTO-wide Hot or Cold Weather Alert or other reasons for conservative operations.

1.3.1D.03 Day-ahead Scheduling Reserves Resources.

"Day-ahead Scheduling Reserves Resources" shall mean synchronized and non-synchronized generation resources and Demand Resources electrically located within the PJM Region that are capable of providing Day-ahead Scheduling Reserves.

1.3.1D.04 Day-ahead Scheduling Reserves Market.

"Day-ahead Scheduling Reserves Market" shall mean the schedule of commitments for the purchase or sale of Day-ahead Scheduling Reserves developed by the Office of the Interconnection as a result of the offers and specifications submitted in accordance with Section 1.10 of this Schedule.

1.3.1D.05 Day-ahead System Energy Price.

"Day-ahead System Energy Price" shall mean the System Energy Price resulting from the Day-ahead Energy Market.

1.3.1E Decrement Bid.

"Decrement Bid" shall mean a bid to purchase energy at a specified location in the Day-ahead Energy Market. An accepted Decrement Bid results in scheduled load at the specified location in the Day-ahead Energy Market.

1.31E.01 Demand Resource.

"Demand Resource" shall mean a resource with the capability to provide a reduction in demand.

1.3.1F Dispatch Rate.

"Dispatch Rate" shall mean the control signal, expressed in dollars per megawatt-hour, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by the Office of the Interconnection in accordance with the Offer Data.

1.3.1G Energy Storage Resource.

"Energy Storage Resource" shall mean flywheel or battery storage facility solely used for short term storage and injection of energy at a later time to participate in the PJM energy and/or Ancilliary Services markets as a Market Seller.

1.3.2 Equivalent Load.

"Equivalent Load" shall mean the sum of a Market Participant's net system requirements to serve its customer load in the PJM Region, if any, plus its net bilateral transactions.

1.3.2A Economic Load Response Participant.

"Economic Load Response Participant" shall mean a Member or Special Member that qualifies under Section 1.5A of this Schedule to participate in the PJM Interchange Energy Market through reductions in demand.

1.3.2A.01 Economic Minimum.

"Economic Minimum" shall mean the lowest incremental MW output level a unit can achieve while following economic dispatch.

1.3.2B Energy Market Opportunity Cost.

"Energy Market Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of available run hours

due to limitations imposed on the unit by Applicable Laws and Regulations (as defined in PJM Tariff), and (b) the forecasted future hourly Locational Marginal Price at which the generating unit could run while not violating such limitations. Energy Market Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same compliance period, which compliance period is determined by the applicable regulatory authority and is reflected in the rules set forth in PJM Manual 15. Energy Market Opportunity Costs shall be limited to those resources which are specifically delineated in Schedule 2 of the Operating Agreement.

1.3.3 External Market Buyer.

"External Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for consumption by end-users outside the PJM Region, or for load in the PJM Region that is not served by Network Transmission Service.

1.3.4 External Resource.

"External Resource" shall mean a generation resource located outside the metered boundaries of the PJM Region.

1.3.5 Financial Transmission Right.

"Financial Transmission Right" or "FTR" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2 of this Schedule.

1.3.5A Financial Transmission Right Obligation.

"Financial Transmission Right Obligation" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2(b) of this Schedule.

1.3.5B Financial Transmission Right Option.

"Financial Transmission Right Option" shall mean a right to receive Transmission Congestion Credits as specified in Section 5.2.2(c) of this Schedule.

1.3.6 Generating Market Buyer.

"Generating Market Buyer" shall mean an Internal Market Buyer that is a Load Serving Entity that owns or has contractual rights to the output of generation resources capable of serving the Market Buyer's load in the PJM Region, or of selling energy or related services in the PJM Interchange Energy Market or elsewhere.

1.3.7 Generator Forced Outage.

"Generator Forced Outage" shall mean an immediate reduction in output or capacity or removal from service, in whole or in part, of a generating unit by reason of an Emergency or threatened

Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the PJM Manuals. A reduction in output or removal from service of a generating unit in response to changes in market conditions shall not constitute a Generator Forced Outage.

1.3.8 Generator Maintenance Outage.

"Generator Maintenance Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit in order to perform necessary repairs on specific components of the facility, if removal of the facility meets the guidelines specified in the PJM Manuals.

1.3.9 Generator Planned Outage.

"Generator Planned Outage" shall mean the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of the Office of the Interconnection in accordance with the PJM Manuals.

1.3.9A Increment Bid.

"Increment Bid" shall mean an offer to sell energy at a specified location in the Day-ahead Energy Market. An accepted Increment Bid results in scheduled generation at the specified location in the Day-ahead Energy Market.

1.3.9B Interface Pricing Point.

"Interface Pricing Point" shall have the meaning specified in section 2.6A.

1.3.10 Internal Market Buyer.

"Internal Market Buyer" shall mean a Market Buyer making purchases of energy from the PJM Interchange Energy Market for ultimate consumption by end-users inside the PJM Region that are served by Network Transmission Service.

1.3.11 Inadvertent Interchange.

"Inadvertent Interchange" shall mean the difference between net actual energy flow and net scheduled energy flow into or out of the individual Control Areas operated by PJM.

1.3.11.01 Load Management.

"Load Management" shall mean either a Demand Resource ("DR") or an Interruptible Load for Reliability ("ILR") resource, both as defined in the Reliability Assurance Agreement.

1.3.11A Load Reduction Event.

"Load Reduction Event" shall mean a reduction in demand by a Member or Special Member for the purpose of participating in the PJM Interchange Energy Market.

1.3.11B Loss Price.

"Loss Price" shall mean the loss component of the Locational Marginal Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.12 Market Operations Center.

"Market Operations Center" shall mean the equipment, facilities and personnel used by or on behalf of a Market Participant to communicate and coordinate with the Office of the Interconnection in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

1.3.12A Maximum Emergency.

"Maximum Emergency" shall mean the designation of all or part of the output of a generating unit for which the designated output levels may require extraordinary procedures and therefore are available to the Office of the Interconnection only when the Office of the Interconnection declares a Maximum Generation Emergency and requests generation designated as Maximum Emergency to run. The Office of the Interconnection shall post on the PJM website the aggregate amount of megawatts that are classified as Maximum Emergency.

1.3.13 Maximum Generation Emergency.

"Maximum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection to address either a generation or transmission emergency in which the Office of the Interconnection anticipates requesting one or more Generation Capacity Resources, or Non-Retail Behind The Meter Generation resources to operate at its maximum net or gross electrical power output, subject to the equipment stress limits for such Generation Capacity Resource or Non-Retail Behind The Meter resource in order to manage, alleviate, or end the Emergency.

1.3.14 Minimum Generation Emergency.

"Minimum Generation Emergency" shall mean an Emergency declared by the Office of the Interconnection in which the Office of the Interconnection anticipates requesting one or more generating resources to operate at or below Normal Minimum Generation, in order to manage, alleviate, or end the Emergency.

1.3.14A NERC Interchange Distribution Calculator.

"NERC Interchange Distribution Calculator" shall mean the NERC mechanism that is in effect and being used to calculate the distribution of energy, over specific transmission interfaces, from energy transactions.

1.3.14B Net Benefits Test.

"Net Benefits Test" shall mean a calculation to determine whether the benefits of a reduction in price resulting from the dispatch of Economic Load Response exceeds the cost to other loads resulting from the billing unit effects of the load reduction, as specified in Section 3.3A.4 of this Schedule.

1.3.15 Network Resource.

"Network Resource" shall have the meaning specified in the PJM Tariff.

1.3.16 Network Service User.

"Network Service User" shall mean an entity using Network Transmission Service.

1.3.17 Network Transmission Service.

"Network Transmission Service" shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part III of the PJM Tariff, or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.

1.3.17A Non-Regulatory Opportunity Cost.

"Non-Regulatory Opportunity Cost" shall mean the difference between (a) the forecasted cost to operate a specific generating unit when the unit only has a limited number of starts or available run hours resulting from (i) the physical equipment limitations of the unit, for up to one year, due to original equipment manufacturer recommendations or insurance carrier restrictions, (ii) a fuel supply limitation, for up to one year, resulting from an event of force majeure; and, (b) the forecasted future hourly Locational Marginal Price at which the generating unit could run while not violating such limitations. Non-Regulatory Opportunity Cost therefore is the value associated with a specific generating unit's lost opportunity to produce energy during a higher valued period of time occurring within the same period of time in which the unit is bound by the referenced restrictions, and is reflected in the rules set forth in PJM Manual 15. Non-Regulatory Opportunity Costs shall be limited to those resources which are specifically delineated in Schedule 2 of the Operating Agreement.

1.3.17B Non-Synchronized Reserve.

"Non-Synchronized Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes of a request from the Office of the Interconnection dispatcher, and is provided by equipment that is not electrically synchronized to the Transmission System.

1.3.17C Non-Synchronized Reserve Event.

"Non-Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources and/or Demand Resources able, assigned or self-scheduled, to provide Non-Synchronized Reserve within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-schedule Non-Synchronized Reserve capability.

1.3.17D Non-Variable Loads.

"Non-Variable Loads" shall have the meaning specified in section 1.5A.6 of this Schedule.

1.3.18 Normal Maximum Generation.

"Normal Maximum Generation" shall mean the highest output level of a generating resource under normal operating conditions.

1.3.19 Normal Minimum Generation.

"Normal Minimum Generation" shall mean the lowest output level of a generating resource under normal operating conditions.

1.3.20 Offer Data.

"Offer Data" shall mean the scheduling, operations planning, dispatch, new resource, and other data and information necessary to schedule and dispatch generation resources and Demand Resource(s) for the provision of energy and other services and the maintenance of the reliability and security of the transmission system in the PJM Region, and specified for submission to the PJM Interchange Energy Market for such purposes by the Office of the Interconnection.

1.3.21 Office of the Interconnection Control Center.

"Office of the Interconnection Control Center" shall mean the equipment, facilities and personnel used by the Office of the Interconnection to coordinate and direct the operation of the PJM Region and to administer the PJM Interchange Energy Market, including facilities and equipment used to communicate and coordinate with the Market Participants in connection with transactions in the PJM Interchange Energy Market or the operation of the PJM Region.

1.3.21A On-Site Generators.

"On-Site Generators" shall mean generation facilities (including Behind The Meter Generation) that (i) are not Capacity Resources, (ii) are not injecting into the grid, (iii) are either synchronized or non-synchronized to the Transmission System, and (iv) can be used to reduce demand for the purpose of participating in the PJM Interchange Energy Market.

1.3.22 Operating Day.

"Operating Day" shall mean the daily 24 hour period beginning at midnight for which transactions on the PJM Interchange Energy Market are scheduled.

1.3.23 Operating Margin.

"Operating Margin" shall mean the incremental adjustments, measured in megawatts, required in PJM Region operations in order to accommodate, on a first contingency basis, an operating contingency in the PJM Region resulting from operations in an interconnected Control Area. Such adjustments may result in constraints causing Transmission Congestion Charges, or may result in Ancillary Services charges pursuant to the PJM Tariff.

1.3.24 Operating Margin Customer.

"Operating Margin Customer" shall mean a Control Area purchasing Operating Margin pursuant to an agreement between such other Control Area and the LLC.

1.3.25 PJM Interchange.

"PJM Interchange" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load exceeds, or is exceeded by, the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup; or (c) the hourly scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the hourly net metered output of any other Market Seller; or (e) the hourly scheduled deliveries of Spot Market Energy to an External Market Buyer; or (f) the hourly scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

1.3.26 PJM Interchange Export.

"PJM Interchange Export" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load is exceeded by the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup sales; or (c) the hourly scheduled deliveries of Spot Market Energy by a Market Seller from an External Resource; or (d) the hourly net metered output of any other Market Seller.

1.3.27 PJM Interchange Import.

"PJM Interchange Import" shall mean the following, as determined in accordance with the Schedules to this Agreement: (a) for a Market Participant that is a Network Service User, the amount by which its hourly Equivalent Load exceeds the sum of the hourly outputs of its operating generating resources; or (b) for a Market Participant that is not a Network Service User, the amount of its Spot Market Backup purchases; or (c) the hourly scheduled deliveries of Spot Market Energy to an External Market Buyer; or (d) the hourly scheduled deliveries to an Internal Market Buyer that is not a Network Service User.

1.3.28 PJM Open Access Same-time Information System.

"PJM Open Access Same-time Information System" shall mean the electronic communication system for the collection and dissemination of information about transmission services in the PJM Region, established and operated by the Office of the Interconnection in accordance with FERC standards and requirements.

1.3.28A Planning Period Quarter.

"Planning Period Quarter" shall mean any of the following three month periods in the Planning Period: June, July and August; September, October and November; December, January and February; or March, April and May.

1.3.28B Planning Period Balance.

"Planning Period Balance" shall mean the entire period of time remaining in the Planning Period following the month that a monthly auction is conducted.

1.3.29 Point-to-Point Transmission Service.

"Point-to-Point Transmission Service" shall mean transmission service provided pursuant to the rates, terms and conditions set forth in Part II of the PJM Tariff.

1.3.29A PRD Curve

PRD Curve shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29B PRD Provider

PRD Provider shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29C PRD Reservation Price

PRD Reservation Price shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29D PRD Substation

PRD Substation shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29E Price Responsive Demand

Price Responsive Demand shall have the meaning provided in the Reliability Assurance Agreement.

1.3.29F Primary Reserve

"Primary Reserve" "Primary Reserve" shall mean the total reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes of a request from the Office of the Interconnection dispatcher, and is comprised of both Synchronized Reserve and Non-Synchronized Reserve.

1.3.30 Ramping Capability.

"Ramping Capability" shall mean the sustained rate of change of generator output, in megawatts per minute.

1.3.30.01 Real-time Congestion Price.

"Real-time Congestion Price" shall mean the Congestion Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30.02 Real-time Loss Price.

"Real-time Loss Price" shall mean the Loss Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30A Real-time Prices.

"Real-time Prices" shall mean the Locational Marginal Prices resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.30B Real-time Energy Market.

"Real-time Energy Market" shall mean the purchase or sale of energy and payment of Transmission Congestion Charges for quantity deviations from the Day-ahead Energy Market in the Operating Day.

1.3.30B.01 Real-time System Energy Price.

"Real-time System Energy Price" shall mean the System Energy Price resulting from the Office of the Interconnection's dispatch of the PJM Interchange Energy Market in the Operating Day.

1.3.31 Regulation.

"Regulation" shall mean the capability of a specific generation resource or Demand Resource with appropriate telecommunications, control and response capability to increase or decrease its output or adjust load in response to a regulating control signal, in accordance with the specifications in the PJM Manuals.

1.3.31.001 Reserve Penalty Factor.

"Reserve Penalty Factor" shall mean the cost, in $/MWh, associated with being unable to meet a specific reserve requirement in a Reserve Zone. A Reserve Penalty Factor will be defined for each reserve requirement in a Reserve Zone.

1.3.31.01 Residual Auction Revenue Rights.

"Residual Auction Revenue Rights" shall mean incremental stage 1 Auction Revenue Rights created within a Planning Period by an increase in transmission system capability or a change in any other relevant factor that was not modeled pursuant to section 7.5 of Schedule 1 of this Agreement in compliance with section 7.4.2(h) of Schedule 1 of this Agreement, and, if modeled, would have increased the amount of stage 1 Auction Revenue Rights allocated pursuant to section 7.4.2 of Schedule 1 of this Agreement; provided that, the foregoing notwithstanding, Residual Auction Revenue Rights shall exclude: 1) Incremental Auction Revenue Rights allocated pursuant to Part VI of the Tariff; and 2) Auction Revenue Rights allocated to entities that are assigned cost responsibility pursuant to Schedule 6 of this Agreement for transmission upgrades that create such rights.

1.3.31.02 Special Member.

"Special Member" shall mean an entity that satisfies the requirements of Section 1.5A.02 of this Schedule or the special membership provisions established under the Emergency Load Response Program.

1.3.31A [Reserved.]

1.3.31B [Reserved.]

1.3.32 Spot Market Backup.

"Spot Market Backup" shall mean the purchase of energy from, or the delivery of energy to, the PJM Interchange Energy Market in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason.

1.3.33 Spot Market Energy.

"Spot Market Energy" shall mean energy bought or sold by Market Participants through the PJM Interchange Energy Market at System Energy Prices determined as specified in Section 2 of this Schedule.

1.3.33A State Estimator.

"State Estimator" shall mean the computer model of power flows specified in Section 2.3 of this Schedule.

1.3.33B Station Power.

"Station Power" shall mean energy used for operating the electric equipment on the site of a generation facility located in the PJM Region or for the heating, lighting, air-conditioning and office equipment needs of buildings on the site of such a generation facility that are used in the operation, maintenance, or repair of the facility. Station Power does not include any energy (i) used to power synchronous condensers; (ii) used for pumping at a pumped storage facility; (iii) used for compressors at a compressed air energy storage facility; (iv) used for charging an Energy Storage Resource; or (v) used in association with restoration or black start service.

1.3.33B.01 Synchronized Reserve.

"Synchronized Reserve" shall mean the reserve capability of generation resources that can be converted fully into energy or Demand Resources whose demand can be reduced within ten minutes from the request of the Office of the Interconnection dispatcher, and is provided by equipment that is electrically synchronized to the Transmission System.

1.3.33B.02 Synchronized Reserve Event.

"Synchronized Reserve Event" shall mean a request from the Office of the Interconnection to generation resources and/or Demand Resources able, assigned or self-scheduled to provide Synchronized Reserve, within ten minutes, to increase the energy output or reduce load by the amount of assigned or self-scheduled Synchronized Reserve capability.

1.3.33B.03 System Energy Price.

"System Energy Price" shall mean the energy component of the Locational Marginal Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a resource, calculated as specified in Section 2 of Schedule 1 of this Agreement.

1.3.33C Target Allocation.

"Target Allocation" shall mean the allocation of Transmission Congestion Credits as set forth in Section 5.2.3 of this Schedule or the allocation of Auction Revenue Rights Credits as set forth in Section 7.4.3 of this Schedule.

1.3.34 Transmission Congestion Charge.

"Transmission Congestion Charge" shall mean a charge attributable to the increased cost of energy delivered at a given load bus when the transmission system serving that load bus is operating under constrained conditions, or as necessary to provide energy for third-party transmission losses in accordance with Section 9.3, which shall be calculated and allocated as specified in Section 5.1 of this Schedule.

1.3.35 Transmission Congestion Credit.

"Transmission Congestion Credit" shall mean the allocated share of total Transmission Congestion Charges credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section 5.2 of this Schedule.

1.3.36 Transmission Customer.

"Transmission Customer" shall mean an entity using Point-to-Point Transmission Service.

1.3.37 Transmission Forced Outage.

"Transmission Forced Outage" shall mean an immediate removal from service of a transmission facility by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the transmission facility, as specified in the relevant portions of the PJM Manuals. A removal from service of a transmission facility at the request of the Office of the Interconnection to improve transmission capability shall not constitute a Forced Transmission Outage.

1.3.37A Transmission Loading Relief.

"Transmission Loading Relief" shall mean NERC's procedures for preventing operating security limit violations, as implemented by PJM as the security coordinator responsible for maintaining transmission security for the PJM Region.

1.3.37B Transmission Loading Relief Customer.

"Transmission Loading Relief Customer" shall mean an entity that, in accordance with Section 1.10.6A, has elected to pay Transmission Congestion Charges during Transmission Loading Relief in order to continue energy schedules over contract paths outside the PJM Region that are increasing the cost of energy in the PJM Region.

1.3.37C Transmission Loss Charge.

"Transmission Loss Charge" shall mean the charges to each Market Participant, Network Customer, or Transmission Customer for the cost of energy lost in the transmission of electricity from a generation resource to load as specified in Section 5 of this Schedule.

1.3.38 Transmission Planned Outage.

"Transmission Planned Outage" shall mean any transmission outage scheduled in advance for a pre-determined duration and which meets the notification requirements for such outages specified in this Agreement or the PJM Manuals.

1.3.38A Variable Loads.

"Variable Loads" shall have the meaning specified in section 1.5A.6 of this Schedule.

1.3.39 Zonal Base Load.

"Zonal Base Load" shall mean the lowest daily zonal peak load from the twelve month period ending October 21 of the calendar year immediately preceding the calendar year in which an annual Auction Revenue Right allocation is conducted, increased by the projected load growth rate for the relevant Zone.

1.7 General.

1.7.1 Market Sellers.

Only Market Sellers shall be eligible to submit offers to the Office of the Interconnection for the sale of electric energy or related services in the PJM Interchange Energy Market. Market Sellers shall comply with the prices, terms, and operating characteristics of all Offer Data submitted to and accepted by the PJM Interchange Energy Market.

1.7.2 Market Buyers.

Only Market Buyers shall be eligible to purchase energy or related services in the PJM Interchange Energy Market. Market Buyers shall comply with all requirements for making purchases from the PJM Interchange Energy Market.

1.7.2A Economic Load Response Participants.

Only Economic Load Response Participants shall be eligible to participate in the Real-time Energy Market and the Day-ahead Energy Market by submitting offers to the Office of the Interconnection to reduce demand.

1.7.3 Agents.

A Market Participant may participate in the PJM Interchange Energy Market through an agent, provided that the Market Participant informs the Office of the Interconnection in advance in writing of the appointment of such agent. A Market Participant participating in the PJM Interchange Energy Market through an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the PJM Interchange Energy Market, and shall ensure that any such agent complies with the requirements of this Agreement.

1.7.4 General Obligations of the Market Participants.

(a) In performing its obligations to the Office of the Interconnection hereunder, each Market Participant shall at all times (i) follow Good Utility Practice, (ii) comply with all applicable laws and regulations, (iii) comply with the applicable principles, guidelines, standards and requirements of FERC, NERC and Applicable Regional Reliability Councils, (iv) comply with the procedures established for operation of the PJM Interchange Energy Market and PJM Region and (v) cooperate with the Office of the Interconnection as necessary for the operation of the PJM Region in a safe, reliable manner consistent with Good Utility Practice.

(b) Market Participants shall undertake all operations in or affecting the PJM Interchange Energy Market and the PJM Region including but not limited to compliance with all Emergency procedures, in accordance with the power and authority of the Office of the Interconnection with

respect to the operation of the PJM Interchange Energy Market and the PJM Region as established in this Agreement, and as specified in the Schedules to this Agreement and the PJM Manuals. Failure to comply with the foregoing operational requirements shall subject a Market Participant to such reasonable charges or other remedies or sanctions for non-compliance as may be established by the PJM Board, including legal or regulatory proceedings as authorized by the PJM Board to enforce the obligations of this Agreement.

(c) The Office of the Interconnection may establish such committees with a representative of each Market Participant, and the Market Participants agree to provide appropriately qualified personnel for such committees, as may be necessary for the Office of the Interconnection and PJMSettlement to perform its obligations hereunder.

(d) All Market Participants shall provide to the Office of the Interconnection the scheduling and other information specified in the Schedules to this Agreement, and such other information as the Office of the Interconnection may reasonably require for the reliable and efficient operation of the PJM Region and PJM Interchange Energy Market, and for compliance with applicable regulatory requirements for posting market and related information. Such information shall be provided as much in advance as possible, but in no event later than the deadlines established by the Schedules to this Agreement, or by the Office of the Interconnection in conformance with such Schedules. Such information shall include, but not be limited to, maintenance and other anticipated outages of generation or transmission facilities, scheduling and related information on bilateral transactions and self-scheduled resources, and implementation of active load management, interruption of load, Price Responsive Demand, and other load reduction measures. The Office of the Interconnection shall abide by appropriate requirements for the non-disclosure and protection of any confidential or proprietary information given to the Office of the Interconnection by a Market Participant. Each Market Participant shall maintain or cause to be maintained compatible information and communications systems, as specified by the Office of the Interconnection, required to transmit scheduling, dispatch, or other time-sensitive information to the Office of the Interconnection in a timely manner.

(e) Subject to the requirements for Economic Load Response participants in section 1.5A above, each Market Participant shall install and operate, or shall otherwise arrange for, metering and related equipment capable of recording and transmitting all voice and data communications reasonably necessary for the Office of the Interconnection and PJMSettlement to perform the services specified in this Agreement. A Market Participant that elects to be separately billed for its PJM Interchange shall, to the extent necessary, be individually metered in accordance with Section 14 of this Agreement, or shall agree upon an allocation of PJM Interchange between it and the Market Participant through whose meters the unmetered Market Participant's PJM Interchange is delivered. The Office of the Interconnection shall be notified of the allocation by the foregoing Market Participants.

(f) Each Market Participant shall operate, or shall cause to be operated, any generating resources owned or controlled by such Market Participant that are within the PJM Region or otherwise supplying energy to or through the PJM Region in a manner that is consistent with the standards, requirements or directions of the Office of the Interconnection and that will permit the Office of the Interconnection to perform its obligations under this Agreement; provided,

however, no Market Participant shall be required to take any action that is inconsistent with Good Utility Practice or applicable law.

(g) Each Market Participant shall follow the directions of the Office of the Interconnection to take actions to prevent, manage, alleviate or end an Emergency in a manner consistent with this Agreement and the procedures of the PJM Region as specified in the PJM Manuals.

(h) Each Market Participant shall obtain and maintain all permits, licenses or approvals required for the Market Participant to participate in the PJM Interchange Energy Market in the manner contemplated by this Agreement.

(i) Consistent with Section 36.1.1 of the PJM Tariff, to the extent its generating facility is dispatchable, a Market Participant shall submit an Economic Minimum in the Real-time Energy Market that is no greater than the higher of its physical operating minimum or its Capacity Interconnection Rights, as that term is defined in the PJM Tariff, associated with such generating facility under its Interconnection Service Agreement under Attachment O of the PJM Tariff or a wholesale market participation agreement.

1.7.5 Market Operations Center.

Each Market Participant shall maintain a Market Operations Center, or shall make appropriate arrangements for the performance of such services on its behalf. A Market Operations Center shall meet the performance, equipment, communications, staffing and training standards and requirements specified in this Agreement for the scheduling and completion of transactions in the PJM Interchange Energy Market and the maintenance of the reliable operation of the PJM Region, and shall be sufficient to enable (i) a Market Seller or an Economic Load Response Participant to perform all terms and conditions of its offers to the PJM Interchange Energy Market, and (ii) a Market Buyer or an Economic Load Response Participant to conform to the requirements for purchasing from the PJM Interchange Energy Market.

1.7.6 Scheduling and Dispatching.

(a) The Office of the Interconnection shall schedule and dispatch in real-time generation resources and/or Demand Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Sellers, continuing until sufficient generation resources and/or Demand Resources are dispatched to serve the PJM Interchange Energy Market energy purchase requirements under normal system conditions of the Market Buyers (taking into account any reductions to such requirements in accordance with PRD Curves properly submitted by PRD Providers), as well as the requirements of the PJM Region for ancillary services provided by generation resources and/or Demand Resources, in accordance with this Agreement. Such scheduling and dispatch shall recognize transmission constraints on coordinated flowgates external to the Transmission System in accordance with Appendix A to the Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (PJM Rate Schedule FERC No. 38) and on other such flowgates that are coordinated in accordance with agreements between the LLC

and other entities. Scheduling and dispatch shall be conducted in accordance with this Agreement.

(b) The Office of the Interconnection shall undertake to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the PJM Interchange Energy Market, and any relevant procedures of another Control Area, or any tariff (including the PJM Tariff). Upon determining that any such conflict or incompatibility exists, the Office of the Interconnection shall propose tariff or procedural changes, and undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

(c) To protect its generation or distribution facilities, or local Transmission Facilities not under the monitoring responsibility and dispatch control of the Office of the Interconnection, an entity may request that the Office of the Interconnection schedule and dispatch generation or reductions in demand to meet a limit on Transmission Facilities different from that which the Office of the Interconnection has determined to be required for reliable operation of the Transmission System. To the extent consistent with its other obligations under this Agreement, the Office of the Interconnection shall schedule and dispatch generation and reductions in demand in accordance with such request. An entity that makes a request pursuant to this section 1.7.6(c) shall be responsible for all generation and other costs resulting from its request that would not have been incurred by operating the Transmission System and scheduling and dispatching generation in the manner that the Office of the Interconnection otherwise has determined to be required for reliable operation of the Transmission System.

1.7.7 Pricing.

The price paid for energy bought and sold in the PJM Interchange Energy Market and for demand reductions will reflect the hourly Locational Marginal Price at each load and generation bus, determined by the Office of the Interconnection in accordance with this Agreement. Transmission Congestion Charges and Transmission Loss Charges, which shall be determined by differences in Congestion Prices and Loss Prices in an hour, shall be calculated by the Office of the Interconnection, and collected by PJMSettlement, and the revenues therefrom shall be disbursed by PJMSettlement in accordance with this Schedule.

1.7.8 Generating Market Buyer Resources.

A Generating Market Buyer may elect to self-schedule its generation resources up to that Generating Market Buyer's Equivalent Load, in accordance with and subject to the procedures specified in this Schedule, and the accounting and billing requirements specified in Section 3 to this Schedule. PJMSettlement shall not be a contracting party with respect to such self-scheduled or self-supplied transactions.

1.7.9 Delivery to an External Market Buyer.

A purchase of Spot Market Energy by an External Market Buyer shall be delivered to a bus or buses at the electrical boundaries of the PJM Region specified by the Office of the Interconnection, or to load in such area that is not served by Network Transmission Service,

using Point-to-Point Transmission Service paid for by the External Market Buyer. Further delivery of such energy shall be the responsibility of the External Market Buyer.

1.7.10 Other Transactions.

(a) Bilateral Transactions.

(i) In addition to transactions in the PJM Interchange Energy Market, Market Participants may enter into bilateral contracts for the purchase or sale of electric energy to or from each other or any other entity, subject to the obligations of Market Participants to make Generation Capacity Resources available for dispatch by the Office of the Interconnection. Such bilateral contracts shall be for the physical transfer of energy to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its eSchedules and Enhanced Energy Scheduler tools.

(ii) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of energy to a Market Participant inside the PJM Region, title to the energy that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and the further transmission of the energy or further sale of the energy into the PJM Interchange Energy Market shall be transacted by the buyer under the bilateral contract. With respect to all bilateral contracts for the physical transfer of energy to an entity outside the PJM Region, title to the energy shall pass to the buyer at the border of the PJM Region and shall be delivered to the border using transmission service. In no event shall the purchase and sale of energy between Market Participants under a bilateral contract constitute a transaction in the PJM Interchange Energy Market or be construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

(iii) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of energy reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the megawatt hours of such reported transactions to amounts reflecting the expected load and other physical delivery obligations of the buyer under the bilateral contract.

(iv) All payments and related charges for the energy associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection or PJMSettlement. 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 a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

(v) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any Spot Market Backup used to meet the bilateral contract seller's obligation to deliver energy under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new eSchedules or Enhanced Energy Scheduler reporting by the Market Participant and (ii) terminate all of the Market Participant's eSchedules and Enhanced Energy Schedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred. All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the eSchedules and Enhanced Energy Schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection. PJMSettlement shall assign its claims against a seller with respect to a seller's nonpayment for Spot Market Backup to a buyer the extent that the buyer has made an indemnification payment to PJMSettlement with respect to the seller's nonpayment.

(vi) Bilateral contracts that do not contemplate the physical transfer of energy to or from a Market Participant are not subject to this Schedule, shall not be reported to and coordinated with the Office of the Interconnection, and shall not in any way constitute a transaction in the PJM Interchange Energy Market.

(b) Market Participants shall have Spot Market Backup with respect to all bilateral transactions that contemplate the physical transfer of energy to or from a Market Participant, that are not dynamically scheduled pursuant to Section 1.12 and that are curtailed or interrupted for any reason (except for curtailments or interruptions through active load management for load located within the PJM Region).

(c) To the extent the Office of the Interconnection dispatches a Generating Market Buyer's generation resources, such Generating Market Buyer may elect to net the output of such resources against its hourly Equivalent Load. Such a Generating Market Buyer shall be deemed a buyer from the PJM Interchange Energy Market to the extent of its PJM Interchange Imports, and shall be deemed a seller to the PJM Interchange Energy Market to the extent of its PJM Interchange Exports.

(d) A Market Seller may self-supply Station Power for its generation facility in accordance with the following provisions:

(i) A Market Seller may self-supply Station Power for its generation facility during any month (1) when the net output of such facility is positive, or (2) when the net output of such facility is negative and the Market Seller during the same month has available at other of its generation facilities positive net output in an amount at least sufficient to offset fully such negative net output. For purposes of this subsection (d), "net output" of a generation facility during any month means the facility's gross energy output, less the Station Power requirements of such facility, during that month. The determination of a generation facility's or a Market Seller's monthly net output under this subsection (d) will apply only to determine whether the Market Seller self-supplied Station Power during the month and will not affect the price of energy sold or consumed by the Market Seller at any bus during any hour during the month. For each hour when a Market Seller has positive net output and delivers energy into the Transmission System, it will be paid the LMP at its bus for that hour for all of the energy delivered. Conversely, for each hour when a Market Seller has negative net output and has received Station Power from the Transmission System, it will pay the LMP at its bus for that hour for all of the energy consumed.

(ii) Transmission Provider will determine the extent to which each affected Market Seller during the month self-supplied its Station Power requirements or obtained Station Power from third-party providers (including affiliates) and will incorporate that determination in its accounting and billing for the month. In the event that a Market Seller self-supplies Station Power during any month in the manner described in subsection (1) of subsection (d)(i) above, Market Seller will not use, and will not incur any charges for, transmission service. In the event, and to the extent, that a Market Seller self-supplies Station Power during any month in the manner described in subsection (2) of subsection (d)(i) above (hereafter referred to as "remote self-supply of Station Power"), Market Seller shall use and pay for transmission service for the transmission of energy in an amount equal to the facility's negative net output from Market Seller's generation facility(ies) having positive net output. Unless the Market Seller makes other arrangements with Transmission Provider in advance, such transmission service shall be provided under Part II of the PJM Tariff and shall be charged the hourly rate under Schedule 8 of the PJM Tariff for Non-Firm Point-to-Point Transmission Service with an election to pay congestion charges, provided, however, that no reservation shall be necessary for such transmission service and the terms and charges under Schedules 1, 1A, 2 through 6, 9 and 10 of the PJM Tariff shall not apply to such service. The amount of energy that a Market Seller transmits in conjunction with remote self-supply of Station Power will not

be affected by any other sales, purchases, or transmission of capacity or energy by or for such Market Seller under any other provisions of the PJM Tariff.

(iii) A Market Seller may self-supply Station Power from its generation facilities located outside of the PJM Region during any month only if such generation facilities in fact run during such month and Market Seller separately has reserved transmission service and scheduled delivery of the energy from such resource in advance into the PJM Region.

1.7.11 Emergencies.

(a) The Office of the Interconnection, with the assistance of the Members' dispatchers as it may request, shall be responsible for monitoring the operation of the PJM Region, for declaring the existence of an Emergency, and for directing the operations of Market Participants as necessary to manage, alleviate or end an Emergency. The standards, policies and procedures of the Office of the Interconnection for declaring the existence of an Emergency, including but not limited to a Minimum Generation Emergency, and for managing, alleviating or ending an Emergency, shall apply to all Members on a non-discriminatory basis. Actions by the Office of the Interconnection and the Market Participants shall be carried out in accordance with this Agreement, the NERC Operating Policies, Applicable Regional Reliability Council reliability principles and standards, Good Utility Practice, and the PJM Manuals. A declaration that an Emergency exists or is likely to exist by the Office of the Interconnection shall be binding on all Market Participants until the Office of the Interconnection announces that the actual or threatened Emergency no longer exists. Consistent with existing contracts, all Market Participants shall comply with all directions from the Office of the Interconnection for the purpose of managing, alleviating or ending an Emergency. The Market Participants shall authorize the Office of the Interconnection and PJMSettlement to purchase or sell energy on their behalf to meet an Emergency, and otherwise to implement agreements with other Control Areas interconnected with the PJM Region for the mutual provision of service to meet an Emergency, in accordance with this Agreement.

(b) To the extent load must be shed to alleviate an Emergency in a Control Zone, the Office of the Interconnection shall, to the maximum extent practicable, direct the shedding of load within such Control Zone. The Office of the Interconnection may shed load in one Control Zone to alleviate an Emergency in another Control Zone under its control only as necessary after having first shed load to the maximum extent practicable in the Control Zone experiencing the Emergency and only to the extent that PJM supports other control areas (not under its control) in those situations where load shedding would be necessary, such as to prevent isolation of facilities within the Eastern Interconnection, to prevent voltage collapse, or to restore system frequency following a system collapse; provided, however, that the Office of the Interconnection may not order a manual load dump in a Control Zone solely to address capacity deficiencies in another Control Zone. This subsection shall be implemented consistent with North American Electric Reliability Council and applicable reliability council standards.

1.7.12 Fees and Charges.

Each Market Participant, except for Special Members, shall pay all fees and charges of the Office of the Interconnection for operation of the PJM Interchange Energy Market as determined by and allocated to the Market Participant by the Office of the Interconnection in accordance with Schedule 3.

1.7.13 Relationship to the PJM Region.

The PJM Interchange Energy Market operates within and subject to the requirements for the operation of the PJM Region.

1.7.14 PJM Manuals.

The Office of the Interconnection shall be responsible for maintaining, updating, and promulgating the PJM Manuals as they relate to the operation of the PJM Interchange Energy Market. The PJM Manuals, as they relate to the operation of the PJM Interchange Energy Market, shall conform and comply with this Agreement, NERC operating policies, and Applicable Regional Reliability Council reliability principles, guidelines and standards, and shall be designed to facilitate administration of an efficient energy market within industry reliability standards and the physical capabilities of the PJM Region.

1.7.15 Corrective Action.

Consistent with Good Utility Practice, the Office of the Interconnection shall be authorized to direct or coordinate corrective action, whether or not specified in the PJM Manuals, as necessary to alleviate unusual conditions that threaten the integrity or reliability of the PJM Region, or the regional power system.

1.7.16 Recording.

Subject to the requirements of applicable State or federal law, all voice communications with the Office of the Interconnection Control Center may be recorded by the Office of the Interconnection and any Market Participant communicating with the Office of the Interconnection Control Center, and each Market Participant hereby consents to such recording.

1.7.17 Operating Reserves.

(a) The following procedures shall apply to any generation unit subject to the dispatch of the Office of the Interconnection for which construction commenced before July 9, 1996, or any Demand Resource subject to the dispatch of the Office of the Interconnection.

(b) The Office of the Interconnection shall schedule to the Operating Reserve and load-following objectives of the Control Zones of the PJM Region and the PJM Interchange Energy Market in scheduling generation resources and/or Demand Resources pursuant to this Schedule. A table of Operating Reserve objectives for each Control Zone is calculated and published

annually in the PJM Manuals. Reserve levels are probabilistically determined based on the season's historical load forecasting error and forced outage rates.

(c) Nuclear generation resources shall not be eligible for Operating Reserve payments unless: 1) the Office of the Interconnection directs such resources to reduce output, in which case, such units shall be compensated in accordance with section 3.2.3(f) of this Schedule; or 2) the resource submits a request for a risk premium to the Market Monitoring Unit under the procedures specified in Section II.B of Attachment M - Appendix. A nuclear generation resource (i) must submit a risk premium consistent with its agreement under such process, or, (ii) if it has not agreed with the Market Monitoring Unit on an appropriate risk premium, may submit its own determination of an appropriate risk premium to the Office of the Interconnection, subject to acceptance by the Office of the Interconnection, with or without prior approval from the Commission.

(d) PJMSettlement shall be the Counterparty to the purchases and sales of Operating Reserve in the PJM Interchange Energy Market.

1.7.18 Regulation.

(a) Regulation to meet the Regulation objective of each Regulation Zone shall be supplied from generation resources and/or Demand Resources located within the metered electrical boundaries of such Regulation Zone. Generating Market Buyers, and Market Sellers offering Regulation, shall comply with applicable standards and requirements for Regulation capability and dispatch specified in the PJM Manuals.

(b) The Office of the Interconnection shall obtain and maintain for each Regulation Zone an amount of Regulation equal to the Regulation objective for such Regulation Zone as specified in the PJM Manuals.

(c) The Regulation range of a generation unit or Demand Resource shall be at least twice the amount of Regulation assigned as described in the PJM Manuals.

(d) A resource capable of automatic energy dispatch that is also providing Regulation shall have its energy dispatch range reduced by at least twice the amount of the Regulation provided with consideration of the Regulation limits of that resource, as specified in the PJM Manuals.

(e) Qualified Regulation must satisfy the verification tests described in the PJM Manuals.

1.7.19 Ramping.

A generator dispatched by the Office of the Interconnection pursuant to a control signal appropriate to increase or decrease the generator's megawatt output level shall be able to change output at the ramping rate specified in the Offer Data submitted to the Office of the Interconnection for that generator.

1.7.19A Synchronized Reserve.

(a) Synchronized Reserve shall be supplied from generation resources and/or Demand Resources located within the metered boundaries of the PJM Region. Generating Market Buyers, and Market Sellers offering Synchronized Reserve shall comply with applicable standards and requirements for Synchronized Reserve capability and dispatch specified in the PJM Manuals.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone an amount of Primary and Synchronized Reserve equal to the respective Primary and Synchronized Reserve objectives for such Reserve Zone, as specified in the PJM Manuals.

(c) The Synchronized Reserve capability of a generation resource and Demand Resource shall be the increase in energy output or load reduction achievable by the generation resource and Demand Resource within a continuous 10-minute period.

(d) A generation unit capable of automatic energy dispatch that also is providing Synchronized Reserve shall have its energy dispatch range reduced by the amount of the Synchronized Reserve provided. The amount of Synchronized Reserve provided by a generation unit shall serve to redefine the Normal Maximum Generation energy limit of that generation unit in that the amount of Synchronized Reserve provided shall be subtracted from its Normal Maximum Generation energy limit.

1.7.19A.01 Non-Synchronized Reserve.

(a) Non-Synchronized Reserve shall be supplied from generation resources and/or Demand Resources located within the metered boundaries of the PJM Region. Generating Market Buyers and Market Sellers offering Non-Synchronized Reserve shall comply with applicable standards and requirements for Non-Synchronized Reserve capability and dispatch specified in the PJM Manuals.

(b) The Office of the Interconnection shall obtain and maintain for each Reserve Zone an amount of Non-Synchronized Reserve such that the sum of the Synchronized Reserve and Non-Synchronized Reserve meets the Primary Reserve objective for such Reserve Zone, as specified in the PJM Manuals.

(c) The Non-Synchronized Reserve capability of a generation resource and Demand Resource shall be the increase in energy output or load reduction achievable by the generation resource and Demand Resource within a continuous 10-minute period provided that the resource is not synchronized to the system at the initiation of the response.

1.7.19B Bilateral Transactions Regarding Regulation, Synchronized Reserve and Day-ahead Scheduling Reserves.

(a) In addition to transactions in the Regulation market, Synchronized Reserve market, and Day-ahead Scheduling Reserves Market, Market Participants may enter into bilateral contracts

for the purchase or sale of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from each other or any other entity. Such bilateral contracts shall be for the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from a Market Participant and shall be reported to and coordinated with the Office of the Interconnection in accordance with this Schedule and pursuant to the LLC's rules relating to its eMarket tools.

(b) For purposes of clarity, with respect to all bilateral contracts for the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to a Market Participant in the PJM Region, title to the product that is the subject of the bilateral contract shall pass to the buyer at the source specified for the bilateral contract, and any further transactions associated with such products or further sale of such Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves in the markets for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves, respectively, shall be transacted by the buyer under the bilateral contract. In no event shall the purchase and sale of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves between Market Participants under a bilateral contract constitute a transaction in PJM's markets for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves, or otherwise construed to define PJMSettlement as a contracting party to any bilateral transactions between Market Participants.

(c) Market Participants that are parties to bilateral contracts for the purchase and sale and physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves reported to and coordinated with the Office of the Interconnection under this Schedule shall use all reasonable efforts, consistent with Good Utility Practice, to limit the amounts of such reported transactions to amounts reflecting the expected requirements for Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves of the buyer pursuant to such bilateral contracts.

(d) All payments and related charges for the Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves associated with a bilateral contract shall be arranged between the parties to the bilateral contract and shall not be billed or settled by the Office of the Interconnection. The LLC, PJM Settlement, and the Members will not assume financial responsibility for the failure of a party to perform obligations owed to the other party under a bilateral contract reported and coordinated with the Office of the Interconnection under this Schedule.

(e) A buyer under a bilateral contract shall guarantee and indemnify the LLC, PJMSettlement, and the Members for the costs of any purchases by the seller under the bilateral contract in the markets for Regulations, Synchronized Reserve, or Day-ahead Scheduling Reserves used to meet the bilateral contract seller's obligation to deliver Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves under the bilateral contract and for which payment is not made to PJMSettlement by the seller under the bilateral contract, as determined by the Office of the Interconnection. Upon any default in obligations to the LLC or PJMSettlement by a Market Participant, the Office of the Interconnection shall (i) not accept any new eMarket reporting by the Market Participant and (ii) terminate all of the Market Participant's reporting of eMarkets schedules associated with its bilateral contracts previously reported to the Office of the Interconnection for all days where delivery has not yet occurred.

All claims regarding a buyer's default to a seller under a bilateral contract shall be resolved solely between the buyer and the seller. In such circumstances, the seller may instruct the Office of the Interconnection to terminate all of the reported eMarkets schedules associated with bilateral contracts between buyer and seller previously reported to the Office of the Interconnection.

(f) Market Participants shall purchase Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves from PJM's markets for Regulation, Synchronized Reserve, Day-ahead Scheduling Reserves, in quantities sufficient to complete the delivery or receipt obligations of a bilateral contract that has been curtailed or interrupted for any reason, with respect to all bilateral transactions that contemplate the physical transfer of Regulation, Synchronized Reserve, or Day-ahead Scheduling Reserves to or from a Market Participant.

1.7.20 Communication and Operating Requirements.

(a) Market Participants. Each Market Participant shall have, or shall arrange to have, its transactions in the PJM Interchange Energy Market subject to control by a Market Operations Center, with staffing and communications systems capable of real-time communication with the Office of the Interconnection during normal and Emergency conditions and of control of the Market Participant's relevant load or facilities sufficient to meet the requirements of the Market Participant's transactions with the PJM Interchange Energy Market, including but not limited to the following requirements as applicable.

(b) Market Sellers selling from generation resources and/or Demand Resources within the PJM Region shall: report to the Office of the Interconnection sources of energy and Demand Resources available for operation; supply to the Office of the Interconnection all applicable Offer Data; report to the Office of the Interconnection generation resources that are self-scheduled; with respect to generation resources, report to the Office of the Interconnection bilateral sales transactions to buyers not within the PJM Region; confirm to the Office of the Interconnection bilateral sales to Market Buyers within the PJM Region; respond to the Office of the Interconnection's directives to start, shutdown or change output levels of generation units, or change scheduled voltages or reactive output levels of generation units, or reduce load from Demand Resources; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, generating equipment and Demand Resources are operated with control equipment functioning as specified in the PJM Manuals.

(c) Market Sellers selling from generation resources outside the PJM Region shall: provide to the Office of the Interconnection all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to Office of the Interconnection directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the Market Seller's Control Area.

(d) Market Participants that are Load Serving Entities or purchasing on behalf of Load Serving Entities shall: respond to Office of the Interconnection directives for load management steps; report to the Office of the Interconnection Generation Capacity Resources to satisfy capacity obligations that are available for pool operation; report to the Office of the

Interconnection all bilateral purchase transactions; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(e) Market Participants that are not Load Serving Entities or purchasing on behalf of Load Serving Entities shall: provide to the Office of the Interconnection requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the PJM Interchange Energy Market, along with Dispatch Rate levels above which it does not desire to purchase; respond to other Office of the Interconnection directives such as those required during Emergency operation.

(f) Economic Load Response Participants are responsible for maintaining demand reduction information, including the amount and price at which demand may be reduced. The Economic Load Response Participant shall provide this information to the Office of the Interconnection by posting it on the Load Response Program Registration link of the PJM website as required by the PJM Manuals. The Economic Load Response Participant shall notify the Office of the Interconnection of a demand reduction concurrent with, or prior to, the beginning of such demand reduction in accordance with the PJM Manuals. In the event that an Economic Load Response Participant chooses to measure load reductions using a Customer Baseline Load, the Economic Load Response Participant shall inform the Office of the Interconnection of a change in its operations or the operations of the end-use customer that would affect a relevant Customer Baseline Load as required by the PJM Manuals.

(g) PRD Providers shall be responsible for ensuring automated reductions to their Price Responsive Demand in response to price in accordance with their PRD Curves submitted to the Office of the Interconnection.

1.10 Scheduling.

1.10.1 General.

(a) The Office of the Interconnection shall administer scheduling processes to implement a Day-ahead Energy Market and a Real-time Energy Market. PJMSettlement shall be the Counterparty to the purchases and sales of energy that clear the Day-ahead Energy Market and the Real-time Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a Generating Market Buyer's self-schedule or self-supply of its generation resources up to that Generating Market Buyer's Equivalent Load.

(b) The Day-ahead Energy Market shall enable Market Participants to purchase and sell energy through the PJM Interchange Energy Market at Day-ahead Prices and enable Transmission Customers to reserve transmission service with Transmission Congestion Charges and Transmission Loss Charges based on locational differences in Day-ahead Prices. Up-To Congestion transactions submitted in the Day-ahead Energy Market shall not require transmission service and Transmission Customers shall not reserve transmission service for such transactions. Market Participants whose purchases and sales, and Transmission Customers whose transmission uses are scheduled in the Day-ahead Energy Market, shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, at the applicable Day-ahead Prices for the amounts scheduled.

(c) In the Real-time Energy Market, Market Participants that deviate from the amounts of energy purchases or sales, or Transmission Customers that deviate from the transmission uses, scheduled in the Day-ahead Energy Market shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling shall be conducted as specified below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such Emergency, in

accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM Manuals.

1.10.1A Day-ahead Energy Market Scheduling.

The following actions shall occur not later than 12:00 noon on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the Office of the Interconnection in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Schedule.

(a) Each Market Participant may submit to the Office of the Interconnection specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the PJM Manuals. Each Market Buyer shall inform the Office of the Interconnection of the prices, if any, at which it desires not to include its load in the Day-ahead Energy Market rather than pay the Day-ahead Price. PRD Providers that have committed Price Responsive Demand in accordance with the Reliability Assurance Agreement shall submit to the Office of the Interconnection, in accordance with procedures specified in the PJM Manuals, any desired updates to their previously submitted PRD Curves, provided that such updates are consistent with their Price Responsive Demand commitments, and provided further that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue may only submit PRD Curves for the Real-time Energy Market. Price Responsive Demand that has been committed in accordance with the Reliability Assurance Agreement shall be presumed available for the next Operating Day in accordance with the most recently submitted PRD Curve unless the PRD Curve is updated to indicate otherwise. PRD Providers may also submit PRD Curves for any Price Responsive Demand that is not committed in accordance with the Reliability Assurance Agreement; provided that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue may only submit PRD Curves for the Real-time Energy Market. All PRD Curves shall be on a PRD Substation basis, and shall specify the maximum time period required to implement load reductions.

(b) Each Generating Market Buyer shall submit to the Office of the Interconnection: (i) hourly schedules for resource increments, including hydropower units, self-scheduled by the Market Buyer to meet its Equivalent Load; and (ii) the Dispatch Rate at which each such self-scheduled resource will disconnect or reduce output, or confirmation of the Market Buyer's intent not to reduce output.

(c) All Market Participants shall submit to the Office of the Interconnection schedules for any bilateral transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection whether the transaction is to be included in the Day-ahead Energy Market. Any Market Participant that elects to include a bilateral transaction in the Day-ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the PJM Manuals), if any, at which it will be wholly or partially curtailed rather than pay Transmission Congestion Charges. The foregoing price specification shall apply to the price difference between the specified bilateral transaction source and sink points in the day-ahead scheduling process only. Any Market Participant that

elects not to include its bilateral transaction in the Day-ahead Energy Market shall inform the Office of the Interconnection if the parties to the transaction are not willing to incur Transmission Congestion Charges in the Real-time Energy Market in order to complete any such scheduled bilateral transaction. Scheduling of bilateral transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

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

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

iii) In addition to the foregoing schedules for bilateral transactions, Market Participants shall submit confirmations of each scheduled bilateral transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(d) Market Sellers wishing to sell into the Day-ahead Energy Market shall submit offers for the supply of energy (including energy from hydropower units), demand reductions, Regulation, Operating Reserves or other services for the following Operating Day. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Attachment DD of the PJM Tariff, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. Any offer not designated as a Maximum Emergency Offer shall be considered available for scheduling and dispatch under both Emergency and non-Emergency conditions. Offers may only be designated as Maximum Emergency Offers to the extent that the Generation Capacity Resource falls into at least one of the following categories:

i) Environmental limits. If the resource has a limit on its run hours imposed by a federal, state or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited to operating only during declared PJM capacity emergencies by a governmental authority.

ii) Fuel limits. If physical events beyond the control of the resource owner result in the temporary interruption of fuel supply and there is limited on-site fuel storage. A fuel supplier's exercise of a contractual right to interrupt supply or delivery under an

interruptible service agreement shall not qualify as an event beyond the control of the resource owner.

iii) Temporary emergency conditions at the unit. If temporary emergency physical conditions at the resource significantly limit its availability.

iv) Temporary megawatt additions. If a resource can provide additional megawatts on a temporary basis by oil topping, boiler over-pressure, or similar techniques and such megawatts are not ordinarily otherwise available.

The submission of offers for resource increments that have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Schedule 2 of the Operating Agreement, and PJM Manuals, as applicable. Energy offered from generation resources that have not cleared a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region. The foregoing offers:

i) Shall specify the Generation Capacity Resource or Demand Resource and energy or demand reduction amount, respectively, for each hour in the offer period, and the minimum run time for generation resources and minimum down time for Demand Resources;

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

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

iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;

v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with a second schedule applicable if accepted after the foregoing deadline;

vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer, which offer shall remain open through the Operating Day for which the offer is submitted;

vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day; and

viii) Shall not exceed an energy offer price of $1,000/megawatt-hour for all generation resources and Demand Resources that have cleared a Base Residual Auction or an Incremental Auction.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation that shall specify the megawatt of Regulation being offered, which must equal or exceed 0.1 megawatts, the Regulation Zone for which such regulation is offered, the price of the capability offer in dollars per MW, the price of the performance offer in Dollars per change in MW, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the resource's opportunity costs. The total of the performance offer multiplied by the historical average mileage used in the market clearing plus the capability offer shall not exceed $100 per MWh in the case of Regulation offered for all Regulation Zones. In addition to any market-based offer for Regulation, the Market Seller also shall submit a cost-based offer. A cost-based offer must be in the form specified in the PJM Manuals and consist of the following components as well as any other components specified in the PJM Manuals:

i. The costs (in $/MW) of the fuel cost increase due to the heat rate increase resulting from operating a unit at lower megawatt output incurred from the provision of Regulation;

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

iii. An adder of up to $12.00 per megawatt of Regulation provided applied to the capability offer.

Qualified Regulation capability must satisfy the measurement and verification tests specified in the PJM Manuals.

(f) Each Market Seller owning or controlling the output of a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative shall submit a forecast of the availability of each such Generation Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with start-up and no-load fees, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours.

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

(h) The Office of the Interconnection shall post the total hourly loads scheduled in the Day-ahead Energy Market, as well as, its estimate of the combined hourly load of the Market Buyers for the next four days, and peak load forecasts for an additional three days.

(i) Except for Economic Load Response Participants, all Market Participants may submit Increment Bids and/or Decrement Bids that apply to the Day-ahead Energy Market only. Such bids must comply with the requirements set forth in the PJM Manuals and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-ahead Energy Market. The Office of the Interconnection may require that a market participant shall not submit in excess of 3000 bid/offer segments in the Day-ahead Energy Market, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to 10:00 a.m. EPT on the day that the Day-ahead Energy Market will clear. For purposes of this provision, a bid/offer segment is each pairing of price and megawatt quantity submitted as part of an Increment Bid or Decrement Bid.

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

(k) An Economic Load Response Participant that wishes to participate in the Day-ahead Energy Market by reducing demand shall submit an offer to reduce demand to the Office of the Interconnection. The offer must equal or exceed 0.1 megawatts, and the offer shall specify: (i) the amount of the offered curtailment in minimum increments of .1 megawatts: (ii) the Day-ahead Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, start-up costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum of number of contiguous hours for which the load reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs).

(l) Market Sellers owning or controlling the output of a Demand Resource that was committed in an FRR Capacity Plan, self-supplied or offered and cleared in the Base Residual Auction or one of the Incremental Auctions, or owning or controlling the output of an ILR resource which was certified as specified in Attachment DD of the PJM Tariff, may submit demand reduction bids for the available load reduction capability of the Demand Resource or

ILR resource. The submission of demand reduction bids for resource increments that have not cleared in the Base Residual Auction or in one of the Incremental Auctions, or for ILR resources that were not certified, or were not committed in an FRR Capacity Plan, shall be optional, but any such bids must contain the information specified in the PJM Economic Load Response Program to be included in such bids. A Demand Resource that was committed in an FRR Capacity Plan, self-supplied or offered and cleared in a Base Residual Auction or an Incremental Auction may submit a demand reduction bid in the Day-ahead Energy Market as specified in the Economic Load Response Program, provided however, that in the event of an Emergency, PJM shall require Demand Resources and ILR resources to reduce load notwithstanding that the Zonal LMP at the time such Emergency is declared is below the price identified in the demand reduction bid.

(m) Market Sellers that wish to make Day-ahead Scheduling Reserves Resources available to sell Day-ahead Scheduling Reserves shall submit offers, each of which must equal or exceed 0.1 megawatts, in the Day-ahead Scheduling Reserves Market specifying: 1) the price of the offer in dollars per megawatt hour; and 2) such other information specified by the Office of the Interconnection as may be necessary to determine any relevant opportunity costs for the resource(s). The foregoing notwithstanding, to qualify to submit offers pursuant to this section, the Day-ahead Scheduling Reserves Resources shall submit energy offers in the Day-ahead Energy Market including start-up and shut-down costs for generation resource and Demand Resources, respectively, and all generation resources that are capable of providing Day-ahead Scheduling Reserves that a particular resource can provide that service. The MW quantity of Day-ahead Scheduling Reserves that a particular resource can provide in a given hour will be determined based on the energy offer data submitted in the Day-ahead Energy Market, as detailed in the PJM Manuals.

1.10.2 Pool-scheduled Resources.

Pool-scheduled resources are those resources for which Market Participants submitted offers to sell energy in the Day-ahead Energy Market and offers to reduce demand in the Day-ahead Energy Market, which the Office of the Interconnection scheduled in the Day-ahead Energy Market as well as generators committed by the Office of the Interconnection subsequent to the Day-ahead Energy Market. Such resources shall be committed to provide energy in the real-time dispatch unless the schedules for such units are revised pursuant to Sections 1.10.9 or 1.11. Pool-scheduled resources shall be governed by the following principles and procedures.

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, start-up, no-load and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in Section 1.10.1A.

(b) A resource that is scheduled by a Market Participant to support a bilateral sale, or that is self-scheduled by a Generating Market Buyer, shall not be selected by the Office of the Interconnection as a pool-scheduled resource except in an Emergency.

(c) Market Sellers offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the Office of the Interconnection that is sufficient to enable the Office of the Interconnection to determine the available operating hours of such facilities.

(d) The Market Seller of a resource selected as a pool-scheduled resource shall receive payments or credits for energy, demand reductions or related services, or for start-up and no-load fees, from the Office of the Interconnection on behalf of the Market Buyers in accordance with Section 3 of this Schedule 1. Alternatively, the Market Seller shall receive, in lieu of start-up and no-load fees, its actual costs incurred, if any, up to a cap of the resource's start-up cost, if the Office of the Interconnection cancels its selection of the resource as a pool-scheduled resource and so notifies the Market Seller before the resource is synchronized.

(e) Market Participants shall make available their pool-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone.

(f) Economic Load Response Participants offering to reduce demand shall specify: (i) the amount of the offered curtailment, which offer must equal or exceed 0.1 megawatts, in minimum increments of .1 megawatts; (ii) the real-time Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, shut-down costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum number of contiguous hours for which the load reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Real-time Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs). Economic Load Response Participants offering to reduce demand shall also indicate the hours that the demand reduction is not available.

1.10.3 Self-scheduled Resources.

Self-scheduled resources shall be governed by the following principles and procedures.

(a) Each Generating Market Buyer shall use all reasonable efforts, consistent with Good Utility Practice, not to self-schedule resources in excess of its Equivalent Load.

(b) The offered prices of resources that are self-scheduled, or otherwise not following the dispatch orders of the Office of the Interconnection, shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.

(c) Market Participants shall make available their self-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone, by submitting an offer as to such resources.

(d) A Market Participant self-scheduling a resource in the Day-ahead Energy Market that does not deliver the energy in the Real-time Energy Market, shall replace the energy not

delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

1.10.4 Capacity Resources.

(a) A Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that is selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection. Such a Generation Capacity Resource that does not deliver energy as scheduled shall be deemed to have experienced a Generator Forced Outage to the extent of such energy not delivered. A Market Participant offering such Generation Capacity Resource in the Day-ahead Energy Market shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Energy from a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that has not been scheduled in the Day-ahead Energy Market may be sold on a bilateral basis by the Market Seller, may be self-scheduled, or may be offered for dispatch during the Operating Day in accordance with the procedures specified in this Schedule. Such a Generation Capacity Resource that has not been scheduled in the Day-ahead Energy Market and that has been sold on a bilateral basis must be made available upon request to the Office of the Interconnection for scheduling and dispatch during the Operating Day if the Office of the Interconnection declares a Maximum Generation Emergency. Any such resource so scheduled and dispatched shall receive the applicable Real-time Price for energy delivered.

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

1.10.5 External Resources.

(a) External Resources may submit offers to the PJM Interchange Energy Market, in accordance with the day-ahead and real-time scheduling processes specified above. An External Resource selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection, and except as specified below shall be compensated on the same basis as other pool-scheduled resources. External Resources that are not capable of dynamic dispatch shall, if selected by the Office of the Interconnection on the basis of the Market Seller's Offer Data, be block loaded on an hourly scheduled basis. Market Sellers shall offer External Resources to the PJM Interchange Energy Market on either a resource-specific or an aggregated resource basis. A Market Participant whose pool-scheduled resource does not deliver the energy scheduled in the Day-ahead Energy Market shall replace such energy not delivered as scheduled in the Day-ahead Energy Market with energy from the PJM Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Offers for External Resources from an aggregation of two or more generating units shall so indicate, and shall specify, in accordance with the Offer Data requirements specified by the Office of the Interconnection: (i) energy prices; (ii) hours of energy availability; (iii) a minimum

dispatch level; (iv) a maximum dispatch level; and (v) unless such information has previously been made available to the Office of the Interconnection, sufficient information, as specified in the PJM Manuals, to enable the Office of the Interconnection to model the flow into the PJM Region of any energy from the External Resources scheduled in accordance with the Offer Data.

(c) Offers for External Resources on a resource-specific basis shall specify the resource being offered, along with the information specified in the Offer Data as applicable.

1.10.6 External Market Buyers.

(a) Deliveries to an External Market Buyer not subject to dynamic dispatch by the Office of the Interconnection shall be delivered on a block loaded basis to the bus or buses at the electrical boundaries of the PJM Region, or in such area with respect to an External Market Buyer's load within such area not served by Network Service, at which the energy is delivered to or for the External Market Buyer. External Market Buyers shall be charged (which charge may be positive or negative) at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing bus or buses.

(b) An External Market Buyer's hourly schedules for energy purchased from the PJM Interchange Energy Market shall conform to the ramping and other applicable requirements of the interconnection agreement between the PJM Region and the Control Area to which, whether as an intermediate or final point of delivery, the purchased energy will initially be delivered.

(c) The Office of the Interconnection shall curtail deliveries to an External Market Buyer if necessary to maintain appropriate reserve levels for a Control Zone as defined in the PJM Manuals, or to avoid shedding load in such Control Zone.

1.10.6A Transmission Loading Relief Customers.

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

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

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

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

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

1.10.7 Bilateral Transactions.

Bilateral transactions as to which the parties have notified the Office of the Interconnection by the deadline specified in Section 1.10.1A that they elect not to be included in the Day-ahead Energy Market and that they are not willing to incur Transmission Congestion Charges in the Real-time Energy Market shall be curtailed by the Office of the Interconnection as necessary to reduce or alleviate transmission congestion. Bilateral transactions that were not included in the Day-ahead Energy Market and that are willing to incur congestion charges and bilateral transactions that were accepted in the Day-ahead Energy Market shall continue to be implemented during periods of congestion, except as may be necessary to respond to Emergencies.

1.10.8 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers and PRD Curves properly submitted by Load Serving Entities for the Price Responsive Demand loads they serve; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv) the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall

report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) Not earlier than 4:00 p.m. of the day before each Operating Day, or such other deadline as may be specified by the Office of the Interconnection in the PJM Manuals, the Office of the Interconnection shall: (i) post the aggregate Day-ahead Energy Market results; (ii) post the Day-ahead Prices; and (iii) inform the Market Sellers, Market Buyers, and Economic Load Response Participants of their scheduled injections, withdrawals, and demand reductions respectively.

(c) Following posting of the information specified in Section 1.10.8(b), the Office of the Interconnection shall revise its schedule of generation resources to reflect updated projections of load, conditions affecting electric system operations in the PJM Region, the availability of and constraints on limited energy and other resources, transmission constraints, and other relevant factors.

(d) Market Buyers shall pay PJMSettlement and Market Sellers shall be paid by PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the offer that set the Day-ahead Price is positive. Market Buyers shall be paid by PJMSettlement and Market Sellers shall pay PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the offer that set the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Section 3.3A of this Schedule.

(e) If the Office of the Interconnection discovers an error in prices and/or cleared quantities in the Day-ahead Energy Market, Real-time Energy Market, Ancillary Services Markets or Day Ahead Scheduling Reserve Market after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 12:00 p.m. of the second business day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the second business day following the initial publication of the results for the Day-ahead Scheduling Reserve Market and Day-ahead Energy Market. After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the fifth business day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the fifth business day following the initial publication of the results in the Day-ahead Scheduling Reserve Market and the Day-ahead Energy Market. Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating Day for the Ancillary Services Markets, Day-ahead Energy Market and Real-time Energy Market, and no later than 5:00 p.m. of the tenth calendar day following the initial publication of the results in the Day-ahead Scheduling Reserve Market. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced market results are under publicly noticed review by the FERC.

(f) Consistent with Section 18.17.1 of the PJM Operating Agreement, and notwithstanding anything to the contrary in the Operating Agreement or in the PJM Tariff, to allow the tracking of Market Participants' non-aggregated bids and offers over time as required by FERC Order No. 719, the Office of the Interconnection shall post on its Web site the non-aggregated bid data and Offer Data submitted by Market Participants (for participation in the PJM Interchange Energy Market) approximately four months after the bid or offer was submitted to the Office of the Interconnection.

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, a generation rebidding period shall exist from 4:00 p.m. to 6:00 p.m. on the day before each Operating Day. During the rebidding period, Market Participants may submit revisions to generation Offer Data for any generation resource that was not selected as a pool-scheduled resource in the Day-ahead Energy Market. Adjustments to Day-ahead Energy Markets shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 60 minutes prior to the hour in which the adjustment is to take effect, as follows:

i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;

ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or

iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or

iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any start-up fee.

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

(d) An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase in the Day-ahead Energy Market by notifying the Office of the Interconnection of the adjustment in deliveries not later than 60 minutes prior to the hour in which the adjustment is to take effect, but any such adjustment shall not affect the obligation of the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(e) For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section 1.10, the Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules for the hour.

1.11 Dispatch.

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

1.11.1 Resource Output.

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

1.11.2 Operating Basis.

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

1.11.3 Pool-dispatched Resources.

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

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

1.11.3A Maximum Generation Emergency.

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

1.11.4 Regulation.

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

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

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

1.11.4A Synchronized Reserve.

(a) A Market Buyer may satisfy its Synchronized Reserve Obligation from its own generation resources and/or Demand Resources capable of providing Synchronized Reserve, by

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

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

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

1.11.4B Non-Synchronized Reserve.

(a) A Market Buyer may satisfy its Non-Synchronized Reserve Obligation from its own generation resources and/or Demand Resources capable of providing Non-Synchronized Reserve, by contractual arrangements with other Market Participants able to provide Non-Synchronized Reserve, or by purchases from the PJM Non-Synchronized Reserve Market at the rates set forth in Section 3.2.3A.001.

(b) The Office of the Interconnection shall obtain Non-Synchronized Reserve from the least-cost alternatives available from either pool-scheduled or self-scheduled generation resources and/or Demand Resources as needed to ensure the Primary Reserve requirement of each Reserve Zone of the PJM Region not otherwise satisfied by the Market Buyers. Resources offering to sell Non-Synchronized Reserve shall be selected to provide Non-Synchronized Reserve on the basis of each generation resource's and/or Demand Resource's estimated unit specific opportunity cost of the resource providing Non-Synchronized Reserve, and in accordance with the Office of the Interconnection's obligation to minimize the total cost of energy, Operating Reserves, Synchronized Reserve and other ancillary services. Estimated unit specific opportunity costs for generation resources shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the absolute value of the difference between the Locational marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Non-Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources will be zero.

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

1.11.5 PJM Open Access Same-time Information System.

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

2.2 General.

The Office of the Interconnection shall determine the least cost security-constrained dispatch, which is the least costly means of serving load and meeting reserve requirements at different locations in the PJM Region based on actual operating conditions existing on the power grid (including transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6) and on the prices at which Market Sellers have offered to supply energy and offers by Economic Load Response Participants to reduce demand that qualify to set Locational Marginal Prices in the PJM Interchange Energy Market. Locational Marginal Prices for the generation and load busses in the PJM Region, including interconnections with other Control Areas, will be calculated based on the actual economic dispatch and the prices of energy and demand reduction offers. The process for the determination of Locational Marginal Prices shall be as follows:

(a) To determine actual operating conditions on the power grid in the PJM Region, the Office of the Interconnection shall use a computer model of the interconnected grid that uses available metered inputs regarding generator output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network. The computer model employed for this purpose, referred to as the State Estimator program, is a standard industry tool and is described in Section 2.3 below. It will be used to obtain information regarding the output of generation supplying energy to the PJM Region, loads at busses in the PJM Region, transmission losses, and power flows on binding transmission constraints for use in the calculation of Locational Marginal Prices. Additional information used in the calculation, including Dispatch Rates and real time schedules for external transactions between PJM and other Control Areas and dispatch and pricing information from entities with whom PJM has executed a joint operating agreement, will be obtained from the Office of the Interconnection's dispatchers.

(b) Using the prices at which energy is offered by Market Sellers and demand reductions are offered by Economic Load Response Participants to the PJM Interchange Energy Market, the Office of the Interconnection shall determine the offers of energy and demand reductions that will be considered in the calculation of Locational Marginal Prices. As described in Section 2.4 below, every qualified offer for demand reduction and of energy by a Market Seller from resources that are dispatched by the Office of the Interconnection will be utilized in the calculation of Locational Marginal Prices, including, without limitation, qualified offers from Economic Load Response Participants in either the Day-Ahead or Real-Time Energy Markets that satisfy the Net Benefits Test. Offers of economic load response from Demand Resources in the Real-time Energy Market will not be eligible to set Locational Marginal Prices, unless metered directly by the Office of the Interconnection. Offers of Full Program Option resources in the Emergency Load Response Program are eligible to set real time Locational Marginal Prices when the Office of the Interconnection has implemented Emergency procedures and such resources are required to reduce demand in the PJM Region, so long as sufficient data is available to accurately model the resources.

(c) Based on the system conditions on the PJM power grid, determined as described in (a), and the eligible energy and demand reduction offers, determined as described in (b), the Office of the Interconnection shall determine the least costly means of obtaining energy to serve the next increment of load at each bus in the PJM Region, in the manner described in Section 2.5 below. The result of that calculation shall be a set of Locational Marginal Prices based on the system conditions at the time.

2.3 Determination of System Conditions Using the State Estimator.

Power system operations, including, but not limited to, the determination of the least costly means of serving load and meeting reserve requirements, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In calculating Locational Marginal Prices, the Office of the Interconnection shall obtain a complete and consistent description of conditions on the electric network in the PJM Region by using the most recent power flow solution produced by the State Estimator program and utilized in the PJM dispatch algorithm, which State Estimator program is also used by the Office of the Interconnection for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available real-time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at busses for which real-time information is unavailable. The Office of the Interconnection shall obtain a State Estimator solution every five minutes, which shall provide the megawatt output of generators and the loads at busses in the PJM Region, transmission line losses, and actual flows or loadings on constrained transmission facilities. External transactions between PJM and other Control Areas shall be included in the Locational Marginal Price calculation on the basis of the real time transaction schedules implemented by the Office of the Interconnection's dispatcher.

2.4 Determination of Energy Offers Used in Calculating Real-time Prices.

(a) During the Operating Day, real-time Locational Marginal Prices derived in accordance with this Section shall be determined every five minutes and integrated hourly values of such determinations shall be the basis of sales and purchases of energy in the Real-time Energy Market and of Transmission Congestion Charges under the PJM Tariff not covered by the Day-ahead Energy Market.

(b) To determine the energy offers submitted to the PJM Interchange Energy Market that shall be used during the Operating Day to calculate the Real-time Prices, the Office of the Interconnection shall determine the applicable marginal energy offer of the resources being dispatched by the Office of the Interconnection. A resource shall be included in the calculation of Real-time Prices if the applicable marginal energy offer of the resource being dispatched by the Office of the Interconnection is less than or equal to the Dispatch Rate for the area of the PJM Region in which the resource is located.

(c) In determining whether a resource satisfies the condition described in (b), the Office of the Interconnection will determine the applicable marginal energy offer by comparing the requested megawatt output of the resource with the Market Seller's offer price curve. The applicable marginal energy offer used in the calculation of Real-time Prices shall not exceed the applicable Dispatch Rate. Units that must be run for local area protection shall not be considered in the calculation of Real-time Prices.

2.5 Calculation of Real-time Prices.

(a) The Office of the Interconnection shall determine the least costly means of obtaining energy to serve the next increment of load (taking account of any applicable and available load reductions indicated on PRD Curves properly submitted by any PRD Provider) at each bus in the PJM Region represented in the State Estimator and each Interface Pricing Point between PJM and an adjacent Control Area, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and utilized in the PJM dispatch algorithm and the energy offers that are the basis for the Day-ahead Energy Market, or that are determined to be eligible for consideration under Section 2.4 in connection with the real-time dispatch, as applicable. This calculation shall be made by applying a real-time joint optimization of energy and reserves, given actual system conditions, a set of energy offers, a set of reserve offers, a set of Reserve Penalty Factors, and any binding transmission constraints that may exist. In performing this calculation, the Office of the Interconnection shall calculate the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as the sum of the following components of Locational Marginal Price: (1) System Energy Price, which is the price at which the Market Seller has offered to supply an additional increment of energy from a generation resource or decrease an increment of energy being consumed by a Demand Resource, (2) Congestion Price, which is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from the resource on transmission line loadings, and (3) Loss Price, which is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource based on the effect of increased generation from or consumption by the resource on transmission losses. The real-time Locational Marginal Prices at a bus shall be determined through the joint optimization based on the lowest marginal cost to serve the next increment of load at the bus taking into account the applicable reserve requirements, unit resource constraints, transmission constraints and marginal loss impact.

(b) If all reserve requirements in every modeled Reserve Zone can be met at prices less than or equal to the energy offer cap of $1,000 per megawatt-hour, real-time Locational Marginal Prices shall be calculated as described in Section 2.5(a) above. When a reserve requirement cannot be met at a price less than or equal to be met at prices less than or equal to the energy offer cap of $1,000 per megawatt-hour, the real-time Locational Marginal Prices shall be capped at $1,000 per megawatt-hour.

(c) During the Operating Day, the calculation set forth in (a) shall be performed every five minutes, using the Office of the Interconnection's Locational Marginal Price program, producing a set of Real-time Prices based on system conditions during the preceding interval. The prices produced at five-minute intervals during an hour will be integrated to determine the Real-time Prices for that hour.

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 (g) of this section;the amounts, if any, described in subsection (e) of this section; and (iii) the Internal Market Buyer's pro rata share of any performance credits paid to regulating resources calculated in accordance with subsection (f) 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 such that the calculated credit for each increment of Regulation provided by each resource shall be the Regulation market-clearing price.

(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 (f) 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 from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.3.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation 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 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.

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

(e) 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.

(f) 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 expected amount of Regulation that resource will be dispatched based on the historical ratio of control signals calculated by the Office of the Interconnection, and the ratio of benefits to system control for following the Regulation control signal 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 based on the assigned MW(s), the performance Regulation market-clearing price, the amount of Regulation performance of the resource provides during the market hour, and the accuracy with which each resource responds to the Office of the Interconnection's Regulation signals during the market hour.

(g) 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 (f) 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 capacity Regulation market-clearing price.

(h) 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.

(i) If PJM is unable to meet its Synchronized Reserve requirements as specified in 1.7.19A, the performance Regulation clearing price and the capability Regulation clearing price will be held steady for the duration of the reserve deficiency at the last value calculated prior to the start of the reserve deficiency. In the event of such reserve deficiency, 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 at the higher of (i) the Regulation market-clearing price in such Regulation Zone or (ii) the sum of the regulation offer and the unit-specific opportunity cost of the generation resource supplying the increment of Regulation.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to section 1.10.1A(e) of this Schedule. A Regulation supplier fails the three-pivotal supplier test in any hour in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

(b) For the purposes of conducting the three-pivotal supplier test pursuant to this section, the following applies:

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region for which the 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.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the prices offered for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Section 3.2.3A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves

pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the Day-ahead Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for start-up and no-load fees and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. Except as provided in Section 3.2.3(n), if the total offered price summed over all hours exceeds the total value summed over all hours, the difference shall be credited to the Market Seller. The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations from day-ahead schedules or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve credits, identified as RA Credits for Reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

(c) The sum of the foregoing credits calculated in accordance with Section 3.2.3(b) plus any unallocated charges from Section 3.2.3(h) and 5.1.7, and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program shall be the cost of Operating Reserves in the Day-ahead Energy Market.

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero) and accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside such area pursuant to Section 1.12.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time

Energy Market shall be made whole for each of the following segments: 1) the greater of their day-ahead schedules or minimum run time (minimum down time for Demand Resources); and 2) any block of hours the resource operates at PJM's direction in excess of the greater of its day-ahead schedule or minimum run time (minimum down time for Demand Resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time (minimum down time for Demand Resources) and Segment 2 will include the remainder of the contiguous hours when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

Credits received pursuant to this section shall be equal to the positive difference between a resource's total offered price for start-up (shutdown costs for Demand Resources) and no-load fees and energy, determined on the basis of the resource's scheduled output, and the total value of the resource's energy as determined by the Real-time Energy Market and the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for segment 2 shall exclude start up (shutdown costs for Demand Resources) costs for generation resources.

Except as provided in Section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to Section 3.2.3(b) plus the resource's opportunity cost and less any amounts credited for Synchronized Reserve in excess of the Synchronized Reserve offer plus the resource's opportunity cost and less any amounts credited for providing Reactive Services as specified in Section 3.2.3B, and less any amounts for Day-ahead Scheduling Reserve in excess of the Day-ahead Scheduling Reserve offer plus the resource's opportunity cost, shall be credited to the Market Seller.

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

(f) A Market Seller's steam-electric generating unit or combined cycle unit operating in combined cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the hourly integrated, real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited hourly in an amount equal to {(LMPDMW - AG) x (URTLMP – UB)}, where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

AG equals the actual hourly integrated output of the unit;

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

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

where URTLMP - UB shall not be negative.

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

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described above for a steam unit or combined cycle unit operating in combined cycle mode.

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

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

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

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

UB equals the offer price for the unit, determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based schedule and the offer associated with that

price schedule is less than the cost-based offer provided for the unit, in which case the offer for the unit will be determined from the cost-based schedule; and

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

(f-2) A Market Seller's hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves, plus any redispatch costs incurred in accordance with section 10(a) of this Schedule, shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of the absolute values of its (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.

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 busses that define all interfaces or all hubs are located in the region. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by busses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed in accordance with the following provisions:

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of an Operating Reserve shortage in real-time or where PJM initiates the request for load reductions in real-time in order to avoid an Operating Reserve shortage as described in this Schedule, Section 6A, Scarcity Pricing.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for

purposes other than providing Synchronized Reserve or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in Section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for the PJM Region.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are dynamically scheduled to load outside the PJM Region pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared ("Maximum Generation Emergency Alert"); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the Operating Reserves credit otherwise provided by Section 3.2.3.(b) or Section 3.2.3(e) in connection with marked-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as "MaxGen Conditions"). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Schedule 2 of the Operating Agreement, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the hours that the offer is economic divided by the megawatt hours of energy provided during the hours that the offer is economic. The hours that the offer is economic shall be: (i) the hours that

the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the hours in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any hours required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 12:00 noon on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described in the PJM Manuals. Ramp-limited desired MW values shall be used to determine generation resource real-time deviations from the resource's day-ahead schedules.

The Office of the Interconnection shall calculate a ramp-limited desired MW value for generation resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:

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

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

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

$$RL_Desired_t = AOutput_{t-1} + \left(Ramp_Request_t * Case_Eff_time_{t-1}\right)$$

where:

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

To determine if a 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 Interconnection will determine the unit's MWoff dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the UDS LMP Desired MW.

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and UDS Basepoint, or if its % off dispatch is <= 10, or 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 <= 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 n 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 to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve charges shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve charges shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve charges shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region. For the purposes of this section, the Western Region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, DEOK transmission Zones, and the Eastern Region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones. The regional balancing Operating Reserve rates shall be determined in accordance with the following provisions:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time

deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

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

(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.

3.2.3A Synchronized Reserve.

(a) Each Internal Market Buyer that is a Load Serving Entity shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Synchronized Reserve Zone of the PJM Region, based on the Market Buyer's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Synchronized Reserve Zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). An Internal Market Buyer that does not meet its hourly Synchronized Reserve Obligation shall be charged for the Synchronized Reserve dispatched by the Office of the Interconnection to meet such obligation at the Synchronized Reserve Market Clearing Price determined in accordance with subsection (d) of this section, plus the amounts if any, described in subsections (g), (h) and (i) of this section.

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

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

ii) Credits for Synchronized Reserve provided by generation resources that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the Interconnection energy dispatch signals and instructions ("Tier 2 Synchronized Reserve") shall be the higher of (i) the Synchronized Reserve Market Clearing Price or (ii) the sum of (A) the Synchronized Reserve offer, and (B) the specific opportunity cost of the generation resource supplying the increment of Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

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

(c) The Synchronized Reserve Energy Premium Price is the average of the five-minute Locational Marginal Prices calculated during the Synchronized Reserve Event plus an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

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

(e) In determining the 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 expected Locational Marginal Price at the generation bus for the generation resource times (B) the megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer and (ii) the product of (A) the deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order times (B) the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a Generating Market Buyer selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each hour that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be equal to the sum of (i) the product of (A) the megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer times (B) the Locational Marginal Price at the generation bus of the generation resource, and (ii) the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the difference between the

Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the generation resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource. The opportunity costs for a Demand Resource shall be zero.

(g) Charges for Tier 1 Synchronized Reserve will be allocated in proportion to the amount of Tier 1 Synchronized Reserve applied to each Synchronized Reserve Obligation. In the event Tier 1 Synchronized Reserve is provided by a Market Seller in excess of that Market Seller's Synchronized Reserve Obligation, the remainder of the Tier 1 Synchronized Reserve that is not utilized to fulfill the Seller's obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

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

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

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

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l) is the difference between the generation resource's output or the Demand Resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior

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

(l) The magnitude of response by a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load Demand Resource's consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes.

(m) If PJM is unable to meet its Synchronized Reserve requirements as specified in 1.7.19A, the Synchronized Reserve Market Clearing Price will be held steady for the duration of the reserve deficiency at the last value calculated prior to the start of the reserve deficiency.

3.2.3A.01 Day-ahead Scheduling Reserves.

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

(b) A Day-ahead Scheduling Reserves Resource that receives a Day-ahead Scheduling Reserves schedule pursuant to subsection (a) of this section shall be paid the hourly Day-ahead

Scheduling Reserves Market clearing price for the MW obligation in each hour of the schedule, subject to meeting the requirements of subsection (c) of this section.

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

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

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

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

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the

scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

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

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

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

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit hourly in an amount equal to {(LMPDMW - AG) x (URTLMP - UB)}

where:

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP;

AG equals the actual hourly integrated output of the unit;

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

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

where URTLMP - UB shall not be negative.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

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

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

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

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

UB equals the offer price for the unit determined according to the schedule on which the unit was committed day-ahead, unless such schedule was a price-based

schedule and the offer associated with that price-based schedule is less than the cost-based offer for the unit, in which case the offer for the unit will be determined based on the cost-based schedule; and

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

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to Section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the hourly integrated, real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit hourly in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual hourly integrated output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the hourly integrated real time LMP at the unit's bus and adjusted for any regulation or Tier 2 Synchronized Reserve assignments;

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

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

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the

Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generation unit's bus, (C) the generation unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and

shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained

in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the hourly Synchronized Reserve Market Clearing Price for each hour a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's hourly cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the hourly product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

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

3.2.5 Transmission Loss Charges.

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

3.2.6 Emergency Energy.

(a) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each hour of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(b) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each hour of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(c) The net costs or net revenues associated with sales or purchases of hourly energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each hour of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net PJM Interchange in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Buyer in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market Buyer. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Buyer's internal accounting.

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

Attachment C

Affidavit of Adam J. Keech on Behalf of PJM Interconnection, L.L.C., PJM Director of Dispatch, System Operations

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL REGULATORY COMMISSION

PJM Interconnection, LLC	**)**	**Docket No. ER12-___-000**

AFFIDAVIT OF ADAM J. KEECH
ON BEHALF OF PJM INTERCONNECTION, L.L.C.

I. QUALIFICATIONS

1. My name is Adam J. Keech. I am Director of Dispatch, for PJM Interconnection, L.L.C. ("PJM"). My business address is 955 Jefferson Ave. Norristown, PA 19403.

2. My duties in this role include the management and oversight of all of PJM's control room operators and the functions and tasks they perform each day to maintain the reliability of the PJM system. These duties require me to work closely with PJM's operators on the control room floor everyday and as a result I have firsthand knowledge of dispatch operations and the impacts of energy market rules on system operations.

3. I have served as Director of Dispatch since February 2012 and was previously the Manager of Dispatch since February 2011 until that time. Prior to those roles I worked in the Real-Time Market Operations Department as an Engineer and Senior Engineer between January 2003 and April 2008. Following those roles I worked as Manager of Real-Time Market Operations from April 2008 to February 2011.

4. I hold a Bachelor's of Science in Electrical Engineering from Rutgers University, New Brunswick, NJ and am currently pursuing a Masters of Science in Applied Statistics at West Chester University, West Chester, PA.

II. PURPOSE AND OVERVIEW OF AFFIDAVIT

5. The purpose of my affidavit is to provide an explanation of the additional steps required for PJM system operators to adhere to the rules that govern how PJM's proposal to formulate energy and reserve prices under the Administrative Cap Option during system emergencies can serve as a distraction for system operators during the most crucial periods of system operations.

III. DISCUSSION

Different Operating Paradigms and Additional Responsibilities

6. Under normal operating conditions, the implementation of the joint optimization of energy and reserves will add two major benefits to system operations. First, it will provide and systematic and cost efficient way to allocate energy and reserve quantities on a minute-to-minute basis, and second, it will produce a rational set of prices for energy and reserves that provide appropriate financial incentives to generation and demand resources operate their assets in line with the directions of the RTO to facilitate reliability.

7. The Market Based Pricing Option in this filing proposes to continue to allow this full system optimization during normal and reserve shortage conditions. This alternative requires minimal, if any, administrative support from system operators as there is no artificial break point in system operating conditions where a new set

of market rules are required. It allows the system operators to focus on operating system and not on extraneous tasks required solely for the invocation of complicated pricing measures.

8. The Administrative Cap Option of this filing creates completely different operating paradigms based on different system conditions. Under normal operating conditions, system operators could take advantage of the efficiency and simplicity of the joint optimization of energy and reserves. Minimal manual intervention would be required to ensure all energy and reserve needs remain balanced due to the systematic approach provided by this operating model. However, when either a reserve shortage occurs or one of the existing Scarcity Pricing triggers is invoked, the joint optimization model can no longer be used because it does not produce a set of dispatch instructions or market clearing prices that coincide with administrative pricing rules that are required under market rules proposed under the Administrative Cap Option. Therefore, when scarcity is triggered the joint optimization model used during normal operating conditions must be disabled. Disabling this model would put the onus on the system operator to maintain system reliability during the most critical operating periods using a sub-optimal and administratively burdensome model. As an example, the following additional responsibilities will be required of the system operator under the Administrative Cap Option that will not exist under the Market Based Pricing Option.

a) Manually balance energy and reserve needs as efficiently as possible through manual dispatches.

i. Disabling the joint optimization of energy and reserves will require system operators to manually track reserve needs because the dispatch system will only consider energy. This is an immensely critical task that will likely require additional staffing in the control room if needed. Additionally, because the reserve needs will be tracked manually the cost-effectiveness of such commitments will severely decline from what they would otherwise be under the Market Based Pricing Option's systematic approach. Removing a programmatic way to maintain the energy and reserve balance adds complexity while removing efficiency.

b) Take the administrative steps that are required to implement the current Scarcity Pricing rules.

i. The current Scarcity Pricing rules require the activation of special transmission constraints that are only for scarcity conditions. In addition to enabling these special constraints, system operators need to complete the manual task of re-evaluating the energy logging for all generators within the scarcity pricing region. This is because the current PJM Scarcity Pricing mechanism requires PJM to lift offer-capping in a Scarcity Pricing Region during a Scarcity Pricing event. Therefore, PJM operators are required to check that all units that were previously offer-capped have been logged back on their price-based schedules to ensure these Tariff requirements are met. This task is not only administratively burdensome but introduces a higher possibility of human error being incorporated into market clearing price calculations.

c) Answer additional calls from generation and demand response resource owners about inconsistent pricing.

   i. The Administrative Cap Option requires the independent calculation of energy and reserve prices due to the administrative nature of the model. This inevitably results in energy and reserve prices that are not consistent with each other and require after-the-fact make whole payments because they are unable to rise high enough to accurately value energy and reserves during system shortages. Market prices are intended to provide incentives to asset owners to operate in a manner that improves system reliability but when administrative measures are injected into the price calculations they often do not. These inconsistent prices have in the past resulted in many questions from asset owners regarding the validity and inconsistency of such prices. While the additional calls are burdensome, the more problematic outcome is that generation and demand resource asset operators will typically act in a nature that best behooves them financially unless otherwise directed by PJM. The inconsistent pricing outcomes will likely require more manual dispatches that deviate from market pricing outcomes causing added work for control room operators and additional after-the-fact make whole payments to those resources that have been manually dispatched.

d) Manually dispatch generation resources for local constraints that will not get appropriate dispatch signals and prices due to inefficiencies in the current market rules.

i. The Scarcity Pricing rules in the PJM Tariff promote a regional approach to pricing depending on the emergency procedure actions that have been taken in that region. Under the Market-Based Option, this regional pricing approached is removed so that generation and demand resource assets are dispatched and priced individually based on their value on the system. This allows for accurate dispatch signals and prices to be calculated for basically any circumstance the operator may encounter. The Administrative Cap Option, however, continues this regional approach which has resulted in scenarios where a local constraint that exists within the wider Scarcity Pricing region cannot be dispatched for or priced accurately because of the administrative pricing rules that prevail during emergency operating conditions. This as well results in additional manual dispatches by system operators and consequently after-the-fact make whole payments for resources that are subject to these.

IV. SUMMARY AND CONCLUSION

9. While PJM's system operators are heavily trained and capable of handling all operating conditions, there is a point at which market rules can be more of a hindrance than a help. The Administrative Cap Option approaches this point. Though it does produce higher energy prices during emergency operating conditions when they are most needed, it adds a significant amount of work for system operators without a commensurate positive impact on system reliability. Reserve prices under this model are essentially forgotten which can lead to inappropriate incentives to asset owners. Some of the other side effects such as

the manual reserve tracking and uncertainty regarding actions physical asset owners may take in response to price signals complicate the system operators' ability to manage the system. Worst of all, under the Administrative Cap Option, these complications would occur during the times when the system is the most stressed and the operators need as much certainty as they can get that physical asset owners will act in the most reliable manner for the system. They only serve as distractions that can deter the focus of the system operators when their focus is most needed for reliability.

10. From a system operations perspective, the Market-Based Option is without question superior to the Administrative Cap Option. It presents a model of operational simplicity and coherent market clearing prices at all times especially when they are the most critical. It does not force the operators to focus on administrative tasks that add little or no value to system reliability.

11. This concludes my Affidavit.

Adam J. Keech
PJM Interconnection, L.L.C.
Dated: March 5, 2012

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SS:)
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Commonwealth of Pennsylvania

Township of Lower Providence

Adam J. Keech, being first duly sworn, deposes and says that he has read the foregoing "Affidavit of Adam J. Keech on behalf of PJM Interconnection, L.L.C.," that he is familiar with the contents thereof, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

/s/ _____
Adam J. Keech

Subscribed and sworn to before me this 5th day of March, 2012

/s/ _____
Notary Public

My commission expires: Jan. 4, 2015

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Arlene G. Noonan, Notary Public
Skippack Twp., Montgomery County
My Commission Expires Jan. 4, 2015
MEMBER, PENNSYLVANIA ASSOCIATION OF NOTARIES

Sworn to and subscribed before me

this 5 **day of** March, **20**12

Commonwealth of Pennsylvania

County of Montgomery