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March 4, 2022

The 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. ER22-1200-000*
Intelligent Reserve Deployment

Dear Secretary Bose,

Pursuant to section 205 of the Federal Power Act (“FPA”),¹ and Part 35 of the Federal Energy Regulatory Commission’s (“FERC” or the “Commission”) regulations,² PJM Interconnection, L.L.C. (“PJM”) hereby submits for filing proposed revisions to the PJM Open Access Transmission Tariff (“Tariff”), Attachment K-Appendix, sections 1.11 and 3.2 and the parallel provisions of the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. (“Operating Agreement”), Schedule 1, sections 1.11 and 3.2.³

The Tariff and Operating Agreement revisions submitted herein are designed to implement PJM’s intelligent reserve deployment (“IRD”) construct, which enhances the ability of PJM to use real-time unit-specific input during a synchronized reserve deployment (“spin”) event. Through deployment of the IRD tool, PJM can assure a more precise, readily available response than is available under today’s “all-call” system as detailed below.

On December 15, 2021, the PJM Markets and Reliability Committee (“MRC”) endorsed

¹ 16 U.S.C. § 824d.

² 18 C.F.R. Part 35.

³ The Tariff and Operating Agreement are currently located under PJM’s “Intra-PJM Tariffs” eTariff title, available here: <https://etariff.ferc.gov/TariffBrowser.aspx?tid=1731>. Capitalized terms not otherwise defined herein shall have the same meaning as set forth in the Tariff, Operating Agreement, and the Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region (the “RAA”).

the Tariff and Operating Agreement revisions described herein by a sector-weighted vote with 3.77 in favor, which exceeds the sector weighted 3.335 representing an affirmative vote of two thirds of the sectors.⁴ On January 26, 2022, the PJM Members Committee (“MC”) similarly endorsed the same Tariff revisions by acclamation, with 18 objections and zero abstentions.⁵

Given the improvements to maintaining reliability that deployment of the IRD tool will enable, PJM respectfully urges the Commission to find the proposed revisions to the Tariff and Operating Agreement set forth herein just and reasonable under section 205 of the FPA.

PJM also respectfully requests an effective date of June 1, 2022, for the proposed Tariff and Operating Agreement revisions, as described below.

I. BACKGROUND

Synchronized reserve events are emergency procedures triggered by PJM in order to maintain grid reliability by balancing the power generation needs within a region, in accordance with North American Electric Reliability Corporation (“NERC”) BAL mandatory reliability standards.⁶ Such events can be caused by a variety of conditions, including loss of generation (single large or multiple smaller generators), loss of transmission elements resulting in power import limitations, sudden load influx, and/or system frequency decline due to external factors. PJM’s current response process includes an “all-call” message instructing Market Participants (resource owners) to deploy all available online resources. This manual process requests 100% response from all online resources, regardless of location or reserve assignment.

In 2021, the PJM Operating Committee (“OC”) established the Synchronous Reserve

⁴ The minutes from the December 15, 2021 MRC meeting are available here: <https://www.pjm.com/-/media/committees-groups/committees/mrc/2022/20220126/20220126-caa-draft-minutes-mrc-20211215.ashx>

⁵ The minutes from the January 26, 2022 MC meeting are available here: <https://www.pjm.com/-/media/committees-groups/committees/mc/2022/20220224/20220224-caa-draft-minutes-mc-20220126.ashx>

⁶ See, e.g., NERC Reliability Standards BAL-002.

Deployment Task Force (“SRDTF”), which was charged with (1) exploring ways PJM deploys synchronized reserves; (2) establishing expectations of resources during synchronized reserve events; (3) assessing performance during a synchronized reserve event; and (4) evaluating pricing in the immediate aftermath of a synchronized reserve event. The Tariff revisions submitted herein reflect the SRDTF’s efforts and ultimate recommendations related to PJM’s IRD proposal.

II. DESCRIPTION OF PROPOSED REVISIONS

A. Synchronized Reserve Events Today - Status Quo

During normal operations, PJM operators use real-time security constrained economic dispatch (“RT SCED”) cases to determine the dispatch instructions that are sent to resources. The RT SCED cases take into account system conditions and resource specific market data to come up with an optimized economic solution while respecting operational limitations. The instructions from the approved RT SCED case are fed into the Locational Price Calculator (“LPC”) to determine pricing associated with the dispatch signals.

When PJM dispatchers recognize the need to initiate a Synchronized Reserve directive in response to a system event, such as the loss of a large generation resource within the PJM footprint, immediate response is imperative to the restoration of system frequency and generation/load balance. Immediate response to these types of system events is required under NERC Standard BAL-002-3 to comply with the NERC Disturbance Control Standard (DCS).⁷ As referenced above, PJM’s historic approach when initiating a spin event for immediate response to a system event includes an “all-call” message to Market Participants with an instruction to raise to full output (*i.e.*, deployment of all available online resources). The all-call is purely a communication

⁷ NERC Reliability Standard BAL-002-3 – Disturbance Control Standard, <https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-3.pdf>.

tool meant to disseminate information in a rapid fashion. It does not perform any optimization for economics and operational limitations. PJM's current all-call deployment is imprecise as the instructions are not communicated at an individual resource level. This level of deployment does not offer PJM operators visibility into the expected response either in aggregate, or from any particular resource. Because the current method does not request specific response from individual resources, the actual observed response is often inconsistent among resources.

This inconsistent response from Market Participants results in periods of under and over-response. Specifically, the observed inconsistency between Tier 1 and Tier 2 synchronized resources⁸ was the genesis of this IRD initiative, and the initial focus was on Tier 1 resources, which are not subject to non-performance assessments. Even in instances where Tier 1 resources are used to make up a significant portion of the Synchronous Reserve requirement, Tier 1 resources do not have an incentive to meet the commitment, as these resources are only paid for performance, but do not face penalties for non-performance. This response obligation differs from that of Tier 2 resources, in that Tier 2 resources *are* obligated to perform once a commitment is made, and are subject to potential penalties for non-performance.⁹

Additionally, under the current model, RT SCED cases are not consistently used during an event.¹⁰ Due to the timing of RT SCED case initiation/solution and the system event requiring the

⁸ PJM, *Manual 11: Energy & Ancillary Services Market Operations*, § 4.2 (rev. 118, March 1, 2022) (Synchronized Reserve Market Business Rules), <https://www.pjm.com/-/media/documents/manuals/m11.ashx>. Tier 1 is comprised of all those resources on-line following economic dispatch that are able to ramp up from their current output in response to a Synchronized Reserve Event, or Demand Resources capable of reducing load, within 10 minutes.

⁹ The distinction between Tier 1 and Tier 2 resources was resolved through PJM's pending Reserve Price Formation enhancements. By consolidating Tier 1 and Tier 2 resources into one Synchronous Reserve product that more closely reflects the existing Tier 2 Synchronous Reserve product, Tier 1 resources are now obligated to performance up to their commitment or otherwise face penalty. *See generally* Docket No. EL19-58.

¹⁰ In the Real-time Energy Market, PJM uses an application called Real-Time Security Constrained Economic Dispatch ("RT SCED") to dispatch specific resources in order to maintain the system balance of energy and reserves over a near-term look-ahead period. RT SCED analyzes historical and current system information to anticipate

deployment of reserves, the first available RT SCED case frequently does not reflect the actual resource loss. Also, while there are up to five RT SCED scenarios available to PJM operators, the current PJM tools do not allow for a full optimization of resources for reserves. The quantity of resources currently dispatched via an available RT SCED case may not be greater than or equal to the largest loss contingency. As noted above, the immediate response is managed by PJM dispatchers via manual event initiation in the PJM Energy Management System (“EMS”), followed by an all-call message deploying all available resources. These actions effectively address system reliability (restoration of system frequency and generation/load balance) but the approach is not nearly as efficient as leveraging an available security constrained economic dispatch (“SCED”) case.

Not utilizing RT SCED to deploy reserves creates misalignment of pricing and dispatch instructions. The all-call dispatch instructions are not used by LPC and thus not reflected in the pricing signals. Without using RT SCED to deploy reserves, the pricing signal comes from the previously approved RT SCED case that has not accounted for the spin event loss. It can lead to incorrect and sometimes even conflicting pricing and dispatch signals.¹¹ RT SCED results and instructions are presented to PJM operators to provide visibility into expected changes in output and constraint impacts. As noted above, the all-call instructions direct resource owners to increase resource output (or for Demand Resource, reduce load) in response to an event on the system. The

generator performance to various requests, and to provide accurate information to PJM dispatchers regarding generator operating parameters under multiple scenarios. RT SCED also jointly optimizes energy and flexible synchronized reserves on online, dispatchable resources while honoring current regulation assignments to ensure that PJM’s system needs are met, and produces commitments that are sent to resource owners in real-time. RT SCED produces dispatch solutions, or “cases.” These RT SCED cases use load forecast and other system information that are effective for the look-ahead interval to achieve a dispatch solution that will adequately control those forecasted conditions.

¹¹ See PJM Interconnection L.L.C., *Reserve Deployment Events* at 9-10, Synchronized Reserve Deployment Task Force (April 30, 2021), <https://www.pjm.com/-/media/committees-groups/task-forces/srdtf/2021/20210430/20210430-item-06-reserve-deployment-events.ashx>.

all-call instructions are not visually available to PJM operators, who have to wait and see the level and location of the response. The all-call dispatch, therefore, gives PJM operators less operational awareness compared to RT SCED dispatch. PJM has worked diligently over the past several years to address these shortcomings through this IRD proposal, in conjunction with further alignments to PJM's pricing and dispatch tools and processes under the 5-Minute Dispatch and Pricing initiative.¹²

While the initial IRD implementation will impact the existing PJM Reserve Market construct, the same benefits that apply to the Reserve Price Formation Market changes will also fit well with IRD. Inflexible synchronous reserves will continue to be deployed by IRD and committed flexible reserves will be evaluated and potentially dispatched by IRD during a synchronous reserve event, based on economics and constraints.

B. IRD Proposal

PJM's IRD proposal package is a SCED case that simulates the loss of the largest generation contingency.¹³ A SCED case optimizes dispatch signals to meet load and reserve requirements by evaluating a forward looking scenario using real-time and forecasted inputs. Under this case, inflexible synchronized resources will be converted to energy megawatts and along with existing online resources will be ramped up to make up for the lost megawatts. The SCED case will also procure additional reserves to meet the new largest contingency. PJM's IRD proposal will: (1) send resource specific basepoints to increase output for energy and reserves; (2) generate Locational Marginal Prices ("LMPs") that more accurately represent system dispatch

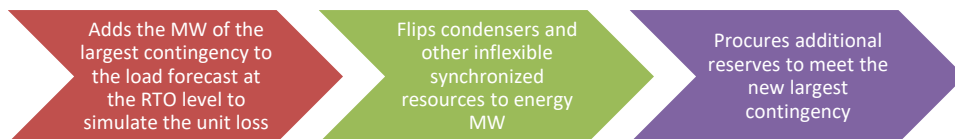
¹² See generally Docket Nos. ER21-1919 and ER20-2573.

¹³ Approval of the case will trigger a deployment event as megawatts of the largest contingency will be added to the load forecast at the RTO level, to simulate the unit loss.

during a spin event; and (3) deploy reserves without violating or overloading currently monitored constraints. This approach results in a lowest production cost solution, honoring system congestion while recovering from the resource that tripped off line. Under the status quo, constraint control is handled through reactive manual actions by PJM operators. The imprecise large-scale deployment through the all-call can lead to violations of multiple constraints. IRD would proactively deploy resources to minimize impact on transmission constraints.

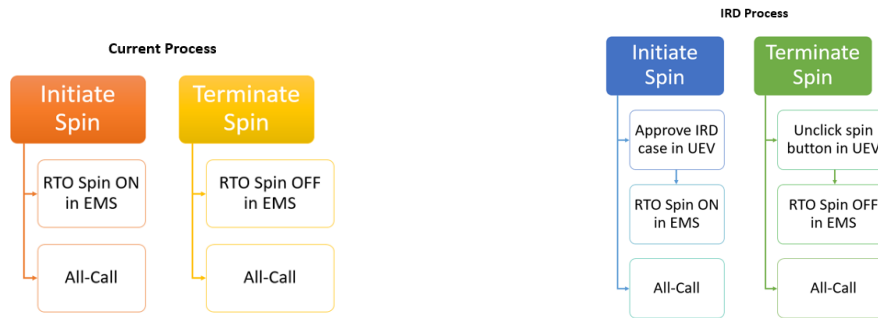
SCED cases use a variety of inputs to perform a complex optimization, which can take several minutes to complete. Even under ideal conditions, waiting for a SCED case to solve will be slower than the all-call implementation. The hallmark of the IRD proposal is that it is readily available to approve at *any* time, initiating a faster response, while subsequent RT SCED cases will continue to solve and be approved to stabilize the system, consistent with PJM’s current processes. Once the PJM dispatcher determines that PJM RTO Area Control Error (ACE)¹⁴ has returned to acceptable levels (at or above the pre-event ACE), dispatchers will terminate the spin event through the SCED application. These changes from the current to the proposed IRD process can be visualized by the following diagrams:

Figure PJM-1¹⁵



¹⁴ See NERC Glossary of Terms Used in NERC Reliability Standards (updated June 28, 2021), https://www.nerc.com/files/glossary_of_terms.pdf. ACE is defined as the instantaneous difference between a Balancing Authority’s net actual and scheduled interchange, taking into account the effects of Frequency Bias, correction for meter error, and Automatic Time Error Correction (ATEC), if operating in the ATEC mode. ATEC is only applicable to Balancing Authorities in the Western Interconnection.

¹⁵ User Experience and Visualization (“UEV”) is the software application used by dispatchers to visualize the SCED case results.



Under the status quo, PJM dispatchers do not leverage SCED software to initiate the spin event in PJM’s EMS. As noted above, the current RT SCED case frequently does not reflect the need for reserve deployment (*i.e.*, loss of a large resource). Therefore, PJM dispatchers are required to manually initiate the spin event in PJM’s EMS. Then, an all-call message is issued with instructions for generating resources to increase output and demand resources to curtail consumption. Depending on factors like RT SCED case availability that adequately reflect the all-call instructions from PJM, RT SCED cases are not always used during spin events. This leaves the unit MW basepoints active from the last approved RT SCED case prior to the event. Those basepoints are often in direct conflict with the all-call instructions. To terminate an event, PJM dispatchers do so in the PJM EMS followed by an all-call message terminating the event.

With IRD, PJM dispatchers would initiate the spin event by using the SCED software to approve the IRD case. The case approval would automatically trigger downstream systems like the EMS. An all-call would still be issued but with revised messaging to follow the instructions in the IRD case. The all-call messaging would align with the MW basepoints from the IRD case while also communicating the urgency to respond to the IRD dispatch instructions. The IRD dispatch instructions will align with pricing providing further incentive for resources to meet their new dispatch set points. PJM dispatchers would also terminate the event in the SCED software.

Today, since all resources are requested to respond during a synchronized reserve event, PJM allows for the aggregation of response between under and over-performing resources on a portfolio basis. However, with the resource specific instructions that come with IRD, aggregation of resource response from the same portfolio (*i.e.*, over-performance from one resource netted with under-performance from another resource in the same Market Seller portfolio) should no longer be allowed when determining performance during events.¹⁶ Some resources within a Market Seller portfolio may specifically not be dispatched during a reserve event as they may: (1) aggravate a transmission constraint; or (2) simply not be needed based on more economic reserve choices. Therefore, because of the resource specific instructions provided by the IRD solution, PJM is not able to support aggregated resource assessments (with the exception of Demand Response which will still be deployed on an aggregated basis).

PJM performs a performance evaluation of all resources during a synchronized reserve event to determine if they are meeting their reserve expectations. Currently, performance evaluation of resources during a synchronized reserve event compares the actual reserves provided to the resource's reserve assignment to determine overall performance and settlement. Under IRD, reserves will be deployed more economically and some resources may not be requested to respond during an event. Therefore, performance evaluation will utilize the lesser of the reserve assignment MW and the expected unit response. The expected unit response will be based on the desired basepoints from the IRD case and any subsequent SCED cases that may be approved prior to the end of the synchronized reserve event. Actual unit response will be measured in a similar manner

¹⁶ Demand Response resources will still be allowed to aggregate, as they follow more of an all or nothing deployment and, as such, are not dispatchable.

as is done currently based on the difference in MW output at the beginning and the end of the event. This actual unit response will be compared to the expected response to determine whether or not the unit met its required reserve response.

1. Better Alignment of Prices With System Conditions

PJM's proposal will better align prices with actual system conditions. As referenced above, the hallmark of the IRD proposal is distinctive: it is readily available to approve at *any* time, initiating a faster response, while subsequent RT SCED cases will continue to solve and be approved to stabilize the system, consistent with PJM's current processes. The Commission has previously articulated the importance of prices reflecting actual operating conditions and needs. For example, in Order No. 825, the Commission stated:

We also require that each regional transmission organization and independent system operator trigger shortage pricing for any interval in which a shortage of energy or operative reserves is indicated during the pricing of resources for that interval. Adopting these reforms will align prices with resource dispatch instruction and operating needs, providing appropriate incentives for resource performance.¹⁷

The Commission further explained that "providing the correct incentives for market participants to follow commitment and dispatch instructions, make efficient investments in facilities and equipment, maintain reliability, and increase transparency is fundamental to proper formation of energy prices, helping to ensure just and reasonable rates, terms and conditions of service."¹⁸ PJM's IRD proposal is aligned with these overarching policy objectives. Importantly, PJM's proposal ensures that shortage pricing is deployed only when warranted by system conditions,

¹⁷ *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 825, 81 Fed. Reg. 42,882 (June 30, 2016), FERC Stats. & Regs. ¶ 31,384, at PP 1-2 & 123 (2016) ("Order No. 825").

¹⁸ *Id.* at P 54.

thereby strengthening the nexus between cost to customers and reliability benefit.

2. *Increased Reliability in PJM Region*

PJM's proposal will increase reliability in the PJM region. In developing this solution package, special consideration was given to the reserve requirements under the NERC BAL standards. This family of standards govern reserve requirements and the requisite timing to recover reserves after a deployment event, among other things. In particular, BAL-002 includes a 90-minute period for reserve restoration (permitting a lower requirement after a deployment event).¹⁹ PJM considers *faster* turnaround under the IRD proposal as the more prudent approach that will enhance reliability. As evidenced by previous events,²⁰ PJM's reserves are recovered very quickly after deployment. While back-to-back events are uncommon, a subsequent event could be triggered within that 90-minute restoration period specified by BAL-002. In such an instance, PJM would need sufficient reserves available *after* that first event, in order to be positioned to recover from the subsequent event. PJM regards the next potential imminent loss as the reliability driver of replenishing reserves in a more expedited manner.

While the status quo to date has proven sufficient to technically meet BAL-002 recovery compliance, PJM's proposal improves upon the current process through a controlled deployment of synchronized reserves utilizing RT SCED. A more controlled deployment of synchronized reserves will improve system reliability during *and after* a reserve deployment event by ensuring continued BAL recovery compliance, coupled with control of transmission constraints and post-

¹⁹ NERC Reliability Standard BAL-002 – Disturbance Control Performance, Requirement R3.

²⁰ See PJM Interconnection L.L.C., *System Operations Report* at 10, Operating Committee (December 2, 2021), <https://www.pjm.com/-/media/committees-groups/committees/oc/2021/20211202/20211202-item-03-review-of-operating-metrics.ashx>. The referenced slide identifies 3 events from November 2021, all of which were completed within 13 minutes.

event generation to load balancing.

Moreover, NERC BAL-002 further requires evidence such as operating plans or other operator documentation that demonstrate that the entity determines its most severe single contingency and that contingency reserves equal to or greater than its most severe single contingency are included in this process. As such, solving for the largest contingency was a significant focus of the SRDTF's efforts and ultimately a critical component of the solution package. Through the stakeholder process, PJM thoughtfully considered the concept of the largest contingency, which is the deployment of reserves based on the largest contingency factor. In crafting this IRD proposal, the largest contingency was the logical starting point, as it is the foundation of the current reserve requirement and PJM's pending Reserve Price Formation efforts.²¹ Through the stakeholder education and exploration process, PJM found the largest contingency to be more dynamic as opposed to a percentage or fixed megawatt value alternative approach, which has a greater potential to fall short in the event of the loss of a unit (or multiple units) on the system. A percentage or fixed megawatt approach also introduces lag time with operators having to choose a value and having to wait for SCED to recalculate before deploying reserves. PJM recognizes that most events will not be triggered by loss of the largest contingency, and as such, PJM's proposal recognizes the need to modify that value based on event experience. As a result, PJM's package has built in flexibility in the form of a readily available IRD case for PJM dispatchers to use in response to a system event, without wavering on the overarching policy objective of improving reliability during synchronized reserve event recovery.

²¹ This concept of largest contingency is referred to as the Minimum Reserve Requirement (MRR) under PJM's Reserve Price Formation efforts.

3. *Proposed Tariff and Operating Agreement Changes*

To implement the revisions to the PJM Tariff and parallel provisions of the Operating Agreement described herein, PJM proposes to amend Tariff, Attachment K-Appendix, sections 1.11.4A(c) and 3.2(j)(k) and the parallel provisions of the Operating Agreement, Schedule 1, sections 1.11.4A(c) and 3.2(j)(k), as shown below:

1.11.4A Synchronized Reserve.

...

(c) Synchronized Reserve Events will be initiated by the Office of the Interconnection by approving the latest solved intelligent reserve deployment (IRD) case in the real-time security constrained economic dispatch application. When initiating a Synchronized Reserve Event, the ~~The~~ Office of the Interconnection shall dispatch generation resources and/or direct the deployment of Demand Resources for Synchronized Reserve by transmitting Synchronized Reserve instructions to generation resources and Demand Resources through approval of the latest available IRD case solution in the real-time security constrained economic dispatch application, 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. In the event the IRD case is not available (as described in Tariff, Attachment K-Appendix, Sections 1.11(b) and (c)), manual Synchronized Reserve deployment will be utilized, in accordance with PJM Manuals.

3.2.3A Synchronized Reserve.

(j) A generation resource or Demand Resource will be credited

for the assigned and/or self-scheduled amount of Tier 2 Synchronized Reserve, less any applicable Tier 2 Synchronized Reserve shortfall, multiplied by the Synchronized Reserve Market Clearing Price for each Real-Time Settlement Interval, in which they were assigned and/or self-scheduled. In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled to provide Tier 2 Synchronized Reserve fails to provide the PJM calculated expected response assigned or self-scheduled amount of Tier 2 Synchronized Reserve in response to a Synchronized Reserve Event, the generation resource or Demand Resource will have a Tier 2 Synchronized Reserve shortfall. will be credited for Tier 2 Synchronized Reserve capacity in the amount that actually responded for The Tier 2 Synchronized Reserve shortfall amount will be the difference between the lesser of the assigned plus self-scheduled amount or the PJM-calculated expected response and the actual response provided. The PJM-calculated expected response is based on the energy dispatch signals and instructions of the Office of the Interconnection. The Tier 2 Synchronized Reserve shortfall amount is for all Real-time Settlement Intervals the generation resource or Demand Resource was assigned and/or self-scheduled Tier 2 Synchronized Reserve on the Operating Day during which the event occurred. The determination of the amount of Synchronized Reserve credited to a generation resource or Demand Resource shall be on an individual resource basis, not on an aggregate basis.

The resource shall refund payments received for Tier 2 Synchronized Reserve it failed to provide. For purposes of determining the amount of the payments to be refunded by a Market Participant, the Office of the Interconnection shall calculate the shortfall of Tier 2 Synchronized Reserve on an individual resource basis unless the Market Participant had multiple Demand Resources that were assigned or self-scheduled to provide Tier 2 Synchronized Reserve, in which case the shortfall will be determined on an aggregate basis. For performance determined on an aggregate basis, the response of any Demand Resource that provided more Tier 2 Synchronized Reserve than it was assigned or self-scheduled to provide will be used to offset the performance of

other Demand Resources that provided less Tier 2 Synchronized Reserve than they were assigned or self-scheduled to provide during a Synchronized Reserve Event, as calculated in the PJM Manuals. The determination of a Market Participant's aggregate response shall not be taken into consideration in the determination of the amount of Tier 2 Synchronized Reserve credited to each individual Demand Resource.

...

(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(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 or increased by the amount the megawatt output of the generation resource ~~falls below~~ differs from 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 but will be capped. If the generation resource has an assignment and the PJM-calculated expected response is greater than the assigned, then the megawatt output will be capped at the difference of the PJM-calculated expected response and the assigned. If the generation resource has no assignment, then the megawatt output will be capped at the PJM-calculated expected response. The PJM-calculated expected response is based on the energy dispatch signals and instructions of the Office of the Interconnection. 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.

4. *Analysis of IRD Pricing Impacts Based on Historical Data*

To provide an idea of the potential outcome of IRD, PJM sampled 2,900 IRD cases using production inputs, 16% (or 474) of which were shortage cases.²² The average system energy price across cases was \$287, compared to the existing first step of the demand curve of \$300. While the average energy price in the sampled IRD cases are generally higher than prices during spin events today, the prices better reflect a significant loss on the system and the operational instructions to recover. Additionally, PJM identified two recent late night RTO level spin events where ample reserves were available. The relevant data showed that IRD pricing reflected system conditions and did not arbitrarily inflate prices despite deploying more than the megawatts lost. Due to the significant amount of synchronized reserves (“SR”) available to be deployed, the IRD pricing was only marginally more than the price during event initiation. This data is visually represented in the following table:

Figure PJM-2

Event	MW Lost	Largest Unit MW	SR Available	Initial Price	IRD Price
6/21 RTO	1,141	1,412	3,230	\$22.09	\$23.42
6/22 RTO	1,188	1,456	2,765	\$19.30	\$19.48

²² See Intelligent Reserve Deployment PJM Package Presentation from the July 1, 2021 SRDTF Meeting, available here: <https://www.pjm.com/-/media/committees-groups/task-forces/srdtf/2021/20210701/20210701-item-03-pjms-proposed-package-intelligent-reserve-deployment.ashx>

III. STAKEHOLDER ENDORSEMENT

On December 15, 2021, the PJM MRC endorsed the Tariff and Operating Agreement revisions described herein by a sector-weighted vote with 3.77 in favor.²³ On January 26, 2022, the PJM MC similarly endorsed the same Tariff revisions by acclamation, with 18 objections (all from the same sector) and zero abstentions.²⁴

IV. EFFECTIVE DATE

PJM respectfully requests an effective date of June 1, 2022, for the proposed Tariff revisions.

V. COMMUNICATIONS

PJM requests that all communications regarding this filing be directed to the following persons:

Craig Glazer
Vice President – Federal Government Policy
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²³ The minutes from the December 15, 2021 MRC meeting are available here: <https://www.pjm.com/-/media/committees-groups/committees/mrc/2022/20220126/20220126-caa-draft-minutes-mrc-20211215.ashx>.

²⁴ The minutes from the January 26, 2022 MC meeting are available here: <https://www.pjm.com/-/media/committees-groups/committees/mc/2022/20220224/20220224-caa-draft-minutes-mc-20220126.ashx>.

VI. DOCUMENTS INCLUDED WITH THIS FILING

In accordance with the requirements of Order No. 714²⁵ and the Commission's eTariff regulations, PJM hereby submits an eTariff XML filing package consisting of the following materials:

1. This transmittal letter;
2. Attachment A – Revisions to the Tariff and Operating Agreement, in redlined format; and
3. Attachment B – Revisions to the Tariff and Operating Agreement, in clean format.

VII. SERVICE

PJM has served a copy of this filing on all PJM Members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,²⁶ 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.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 Region²⁷ alerting them that this filing has been made by PJM today and is available by following such link.

²⁵ *Electronic Tariff Filings*, 124 FERC ¶ 61,270 (2008).

²⁶ See 18 C.F.R §§ 35.2(e) and 385.2010(f)(3).

²⁷ PJM already maintains, updates, and regularly uses e-mail lists for all PJM members and affected commissions.

VIII. CONCLUSION

In accordance with the foregoing, PJM respectfully requests that the Commission accept the proposed revisions to the PJM Tariff and Operating Agreement, and permit an effective date of June 1, 2022, as discussed herein.

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Respectfully submitted,

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On behalf of PJM Interconnection, L.L.C

ATTACHMENT A
REVISIONS TO THE TARIFF AND
OPERATING AGREEMENT
(MARKED)

1.11 Real-time Dispatch.

The Office of the Interconnection shall determine the least cost security constrained economic dispatch and send dispatch targets for each resource to Market Participants. The least cost security constrained economic dispatch is the least costly means of serving load and meeting reserve requirements at different locations in the PJM Region based on forecasted operating conditions on the power grid (including transmission constraints on external coordinated flowgates to the extent provided by Tariff, Attachment K-Appendix, section 1.7.6) as described in the PJM Manuals and on the offers for energy and ancillary services at which Market Sellers have entered as described by Tariff, Attachment K-Appendix, section 1.10 and Tariff, Attachment K-Appendix, section 2.4 and on offers by Economic Load Response Participants to reduce demand that qualify to set Locational Marginal Prices in the PJM Interchange Energy Market.

(a) To determine actual operating conditions on the power grid in the PJM Region (including transmission constraints on external coordinated flowgates to the extent provided by Tariff, Attachment K-Appendix, section 1.7.6), the Office of the Interconnection shall 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 as an input into the real-time security constrained economic dispatch. The computer model employed for this purpose, referred to as the State Estimator program, is a standard industry tool and is described in section 1.11A below. The State Estimator solution used by the real-time security constrained economic dispatch will be used to obtain information regarding the output of generation supplying energy to the PJM Region, loads at buses in the PJM Region, transmission losses, and power flows on binding transmission constraints.

(b) The Office of the Interconnection shall execute real-time security constrained economic dispatch for each five (5) minute target time, unless the Office of the Interconnection is unable to generate real-time security constrained economic dispatch solutions due to operational or technical issues, including but not limited to those described in the PJM Manuals. Each execution of the real-time security constrained economic dispatch shall result in several solutions, taking into consideration different operational scenarios.

(c) The Office of the Interconnection shall approve the applicable real-time security constrained economic dispatch solution for each five (5) minute target time, unless the Office of the Interconnection is unable to approve a real-time security constrained economic dispatch solution for the applicable target time due to a failure of the real-time security constrained economic dispatch program or other operational reasons. In such situations, either the most recently approved real-time security constrained economic dispatch solution shall persist, or the Office of the Interconnection shall manually dispatch the system.

1.11A 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 performing the security constrained economic dispatch of the system, 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. The 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 buses for which real-time information is unavailable. The Office of the Interconnection shall obtain the latest State Estimator solution each time a new security constrained economic dispatch is executed, 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 transmission facilities as defined in the PJM Manuals.

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 or self-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 or self-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.

As part of the real-time security constrained economic dispatch calculation, the Office of the Interconnection shall use submitted ramp rates to calculate the next dispatch point.

As part of the calculation, the Office of the Interconnection shall estimate the initial state of each generation resource based on its previous dispatch signal and the most recent State Estimator output. In the event the Office of the Interconnection is unable to approve a real-time security constrained economic dispatch solution for a period of time, due to a failure of the real-time

security constrained economic dispatch program or other operational reasons, the most recent State Estimator shall be used as the initial state. This evaluation methodology is calculated for all online dispatchable resources for each market solution in accordance with the PJM Manuals.

(a) The Office of the Interconnection shall implement the dispatch of energy from pool-scheduled resources with limited energy by direct request, by following the Day-ahead Market clearing, or by following the direct request of the Market Seller, subject to the Office of the Interconnection's determination of actions necessary to maintain reliability.

(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 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 upon receipt.

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 and Reserve Sub-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 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) Synchronized Reserve Events will be initiated by the Office of the Interconnection by approving the latest solved intelligent reserve deployment (IRD) case in the real-time security constrained economic dispatch application. When initiating a Synchronized Reserve Event, the Office of the Interconnection shall dispatch generation resources and/or direct the deployment of Demand Resources for Synchronized Reserve by transmitting Synchronized Reserve instructions to generation resources and Demand Resources through approval of the latest available IRD case solution in the real-time security constrained economic dispatch application 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. In the event the IRD case is not available (as described in Tariff, Attachment K-Appendix, Sections 1.11(b) and (c)), manual Synchronized Reserve deployment will be utilized, in accordance with PJM Manuals.

1.11.4B Non-Synchronized Reserve.

(a) A Market Buyer may satisfy its Non-Synchronized Reserve Obligation from its own generation 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. PJMSettlement shall be the Counterparty to the purchases and sales of Non-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-supply of generation resources by a Market Buyer to satisfy its Non-Synchronized Reserve Obligation.

(b) The Office of the Interconnection shall obtain Non-Synchronized Reserve from the least-cost alternatives available from either pool-scheduled generation resources, as needed to ensure the Primary Reserve requirement of each Reserve Zone and Reserve Sub-zone of the PJM Region not otherwise satisfied by the Market Buyers. Resources eligible to sell Non-Synchronized Reserve shall be selected to provide Non-Synchronized Reserve on the basis of each generation 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 not providing energy because they are providing Non-Synchronized Reserve shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(c) The Office of the Interconnection shall dispatch generation resources for Non-Synchronized Reserve by sending Non-Synchronized Reserve instructions to generation 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.

3.2 Market Settlements.

If a dollar-per-MW-hour value is applied in a calculation under this section 3.2 where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW hour value is divided by the number of Real-time Settlement Intervals in the hour.

3.2.1 Spot Market Energy.

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

(b) Each Market Participant shall be charged for all of its Market Participant Energy Withdrawals scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price to be served in the PJM Interchange Energy Market.

(c) Each Market Participant shall be paid for all of its Market Participant Energy Injections scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price to be delivered to the PJM Interchange Energy Market.

(d) For each Day-ahead Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its Market Participant Energy Withdrawals scheduled times the Day-ahead System Energy Price and the sum of its Market Participant Energy Injections scheduled times the Day-ahead System Energy Price.

(e) For each Real-time Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its real-time Market Participant Energy Withdrawals less its scheduled Market Participant Energy Withdrawals times the Real-time System Energy Price and the sum of its real-time Market Participant Energy Injections less scheduled Market Participant Energy Injections times the Real-time System Energy Price. The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with section 3.1A of this Schedule shall be used in determining the real-time Market Participant Energy Withdrawals and Market Participant Energy Injections used to calculate Spot Market Energy charges under this subsection (e).

(f) For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the megawatts of real-time energy injections to be delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region

3.2.2 Regulation.

(a) Each Market Participant that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). A Market Participant with an hourly Regulation Obligation shall be charged the pro rata share of the sum of the Regulation market performance clearing price credits and Regulation market capability clearing price credits for the Real-time Settlement Intervals in an hour.

Regulation Charge = Hourly Regulation Obligation Share * (sum of the Real-time Settlement Interval Regulation credits in an hour)

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

(c) The total Regulation market-clearing price in each Regulation Zone shall be determined in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval. The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the

generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

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

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

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

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

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

(e) In determining the credit under subsection (b) to a Market Participant selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for (1) each Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Regulation, and (2) the last three Real-time Settlement Intervals of the preceding shoulder hour and the first three Real-time Settlement Intervals of the following shoulder hour in accordance with the PJM Manuals and below.

The unit-specific opportunity cost incurred during the Real-time Settlement Interval 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 each of the preceding three Real-time Settlement Intervals of the 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 Real-time Settlement Interval in order to provide Regulation and the resource's expected output in each of the preceding three Real-time Settlement Intervals of the shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in each of the preceding three Real-time Settlement Intervals of the 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 Real-time Settlement Interval) in the PJM Interchange Energy Market, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during each of the following three Real-time Settlement Intervals of the 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 Real-time Settlement Interval in order to provide Regulation and the resource's expected output in each of the following three Real-time Settlement Intervals of the shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in each of the following three Real-time Settlement Intervals of the 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 all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Market Participant in a Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

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

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

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

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

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

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

(j) The Office of the Interconnection shall calculate a unit-specific benefits factor for each of the dynamic Regulation signal and traditional Regulation signal in accordance with the PJM Manuals. Each resource shall be assigned a unit-specific benefits factor based on their

order in the merit order stack for the applicable Regulation signal. The unit-specific benefits factor is the point on the benefits factor curve that aligns with the last megawatt, adjusted by historical performance, that resource will add to the dynamic resource stack. Resources following the dynamic Regulation signal which have a unit-specific benefits factor less than 0.1 will not be considered for the purposes of committing resources. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

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

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

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

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

where δ is delay.

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

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

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

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

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

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

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

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

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

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

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

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

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region multiplied by the historic accuracy score of the resource and multiplied by the unit-specific benefits factor for which the capability cost-based offer plus the performance cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The three-pivotal supplier test will apply on a Regulation supplier basis (i.e. not a resource by resource basis) and only the Regulation suppliers that fail the three-pivotal supplier test will have their Regulation offers capped. A Regulation supplier for the purposes of this section includes corporate affiliates. Regulation from resources controlled by a Regulation supplier or its affiliates, whether by contract with unaffiliated third parties or otherwise, will be included as Regulation of that Regulation supplier. Regulation provided by resources owned by a Regulation supplier but controlled by an unaffiliated third party, whether by contract or otherwise, will be included as Regulation of that third party.

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

a third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the applicable offer for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that 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. PJMSettlement shall be the Counterparty to the purchases and sales of Operating Reserve in the PJM Interchange Energy Market.

(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 Costs and No-load Costs and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. PJM shall also (i) determine whether any resources were scheduled in the Day-ahead Energy Market to provide Black Start service, Reactive Services or transfer interface control during the Operating Day because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day in order to minimize the total cost of Operating Reserves associated with the provision of such services and reflect the most accurate possible expectation of real-time operating conditions in the day-ahead model, which resources would not have otherwise been committed in the day-ahead security-constrained dispatch and (ii) report on the day following the Operating Day the megawatt quantities scheduled in the Day-ahead Energy Market for the above-enumerated purposes for the entire RTO.

Except as provided in Section 3.2.3(n), if the total offered price for Start-up Costs (shutdown costs for Demand Resources) and No-load Costs and energy summed over all Day-ahead Settlement Intervals exceeds the total value summed over all Day-ahead Settlement Intervals, the difference shall be credited to the Market Seller as a day-ahead Operating Reserve credit.

However, for the Day-ahead Settlement Intervals in which the resource is scheduled to provide energy in the Operating Day and the resource actually provides energy in at least one Real-time Settlement Interval in an hour that corresponds to such scheduled Day-ahead Settlement Intervals, a resource's day-ahead Operating Reserve credit shall be reduced by the greater of zero or the difference of the resource's Day-ahead Operating Reserve Target and the Balancing Operating Reserve Target, as determined below.

A resource's Day-ahead Operating Reserve Target shall be determined in accordance with the following equation:

$$(A + B) - C$$

Where:

A = Start-up Costs

B = the sum of day-ahead No-load Costs and energy over the applicable Real-time Settlement Intervals that correspond with Day-ahead Settlement Intervals in which the resource is scheduled. The day-ahead No-load Costs and energy are divided by twelve to determine the cost for each Real-time Settlement Interval.

C = the sum of the day-ahead revenues calculated for each Real-time Settlement Interval that corresponds with a Day-ahead Settlement Interval in which the resource is scheduled, where the day-ahead revenue for each such Real-time Settlement Interval equals the product of the megawatt amount of energy scheduled in the Day-ahead Energy Market and the Day-ahead Price at the applicable pricing point for the resource divided by twelve.

A resource's Balancing Operating Reserve Target shall be determined in accordance with the following equation:

$$D - (E + F)$$

Where:

D = the sum of Start-up Costs and No-load Costs and the incremental cost of energy summed over all Real-time Settlement Intervals that correspond to the Day-ahead Settlement Intervals in which the resource was scheduled;

E = [(the megawatt amount of energy provided in the Real-time Energy Market minus the megawatt amount of energy scheduled in the Day-ahead Energy Market) multiplied by the Real-time Price at the applicable pricing point for the resource] plus the sum of the day-ahead revenues as determined in part C of the above formula for determining the Day-ahead Operating Reserve Target, summed over the applicable Real-time Settlement Intervals; and

F = the sum of all revenues earned for providing Day-ahead Scheduling Reserves, Synchronized Reserves, Non-Synchronized Reserves, and Reactive Services over the applicable Real-time Settlement Intervals.

The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this section 3.2.3(b) to real-time deviations or real-time load share plus exports, pursuant to Tariff, Attachment K-Appendix, section 3.2.3(p), 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.

(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), accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day and accepted Up-to Congestion Transactions in the Day-ahead Energy Market in megawatt-hours for the Operating Day at the sink of the transaction; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside such area pursuant to Section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load (net of operating Behind The Meter Generation) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following Segments: 1) the greater of their day-ahead schedules and minimum run time specified at the time of commitment (minimum

down time specified at the time of commitment for Demand Resources); and 2) any block of Real-time Settlement Intervals the resource operates at PJM's direction in excess of the greater of its day-ahead schedule and minimum run time specified at the time of commitment (minimum down time specified at the time of commitment for 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 specified at the time of commitment (minimum down time specified at the time of commitment for Demand Resources) and Segment 2 will include the remainder of the contiguous Real-time Settlement Intervals when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

A Generation Capacity Resource that operates outside of its unit-specific parameters will not receive Operating Reserve Credits nor be made whole for such operation when not dispatched by the Office of the Interconnection, unless the Market Seller of the Generation Capacity Resource can justify to the Office of the Interconnection that operation outside of such unit-specific parameters was the result of an actual constraint. Such Market Seller shall provide to the Market Monitoring Unit and the Office of the Interconnection its request to receive Operating Reserve Credits and/or to be made whole for such operation, along with documentation explaining in detail the reasons for operating its resource outside of its unit-specific parameters, within thirty calendar days following the issuance of billing statement for the Operating Day. The Market Seller shall also respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection. The Market Monitoring Unit shall evaluate such request for compensation and provide its determination of whether there was an exercise of market power to the Office of the Interconnection by no later than twenty-five calendar days after receiving the Market Seller's request for compensation. The Office of the Interconnection shall make its determination whether the Market Seller justified that it is entitled to receive Operating Reserve Credits and/or be made whole for such operation of its resource for the day(s) in question, by no later than thirty calendar days after receiving the Market Seller's request for compensation.

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 Tariff, Attachment K-Appendix, section 3.2.3(f) and the parallel provision of Operating Agreement, Schedule 1, section 3.2.3(f); or 2) the resource submits a request for a risk premium to the Market Monitoring Unit under the procedures specified in Tariff, Attachment M – Appendix, section II.B. A nuclear generation resource (i) must submit a risk premium consistent with its agreement under such process, or, (ii) if it has not agreed with the Market Monitoring Unit on an appropriate risk premium, may submit its own determination of an appropriate risk premium to the Office of the Interconnection, subject to acceptance by the Office of the Interconnection, with or without prior approval from the Commission.

Credits received pursuant to this section shall be equal to the positive difference between a resource's Total Operating Reserve Offer, and the total value of the resource's energy in the

Day-ahead Energy Market plus any credit or change for quantity deviations, at PJM dispatch direction (excluding quantity deviations caused by an increase in the Market Seller's Real-time Offer), from the Day-ahead Energy Market during the Operating Day at the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for Segment 2 shall exclude start up (shutdown costs for Demand Resources) costs for generation resources.

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

Synchronized Reserve, Non-Synchronized Reserve, and Real-time Settlement Interval share of the 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 Real-time Settlement Interval(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 Real-time Settlement Interval the unit operates in condensing and generation mode.

(f) A Market Seller of a unit not defined in subsection (f-1), (f-2), or (f-4) hereof (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than \$0.00. This equation is represented as $(A*B) - C$.

(f-1) With the exception of Market Sellers of Flexible Resources that submit a Real-time Offer greater than their resource's Committed Offer in the Day-ahead Energy Market, a Market Seller of a Flexible Resource shall be compensated for lost opportunity cost, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if either of the following conditions occur:

- (i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described in section 3.2.3 (f).
- (ii) If the unit is scheduled to produce energy in the Day-ahead Energy Market for a Day-ahead Settlement Interval, but the unit is not called on by the Office of the Interconnection and does not operate in the corresponding Real-time Settlement Interval(s), then the Market Seller shall be credited in an amount equal to the higher of:
 - 1) the product of (A) the amount of megawatts committed in the Day-ahead Energy Market for the generating unit, and (B) the Real-time Price at the generation bus for the generating unit, minus the sum of (C) the Total Lost Opportunity Cost Offer plus No-load Costs, plus (D) the Start-up Cost, divided by the Real-time Settlement Intervals committed for each set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market. This equation is represented as $(A*B) - (C+D)$. The startup cost, (D), shall be excluded from this calculation if the unit operates in real time following the Office of the Interconnection's direction during any portion of the set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market, or
 - 2) the Real-time Price at the unit's bus minus the Day-ahead Price at the unit's bus, multiplied by the number of megawatts committed in the Day-ahead Energy Market for the generating unit.

Market Sellers of Flexible Resources that submit a Real-time Offer greater than their resource's Committed Offer in the Day-ahead Energy Market shall not be eligible to receive compensation for lost opportunity costs under any applicable provisions of Schedule 1 of this Agreement.

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

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output

due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-4) A Market Seller of a wind generating unit that is pool-scheduled or self-scheduled, has SCADA capability to transmit and receive instructions from the Office of the Interconnection, has provided data and established processes to follow PJM basepoints pursuant to the requirements for wind generating units as further detailed in this Agreement, the Tariff and the PJM Manuals, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the , real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than \$0.00. This equation is represented as $(A*B) - C$.

(f-5) (i) A Market Seller of a pool-scheduled resource or a dispatchable self-scheduled resource shall receive Dispatch Differential Lost Opportunity Cost credits as calculated under subsection (iv) below if the resource is dispatched to provide energy in the Real-time Energy Market, provided such resource is not committed to provide real-time ancillary services (Regulation, reserves, reactive service) or instructed to reduce or suspend output due to a transmission constraint or other reliability issue pursuant to Tariff, Attachment K-Appendix, section 3.2.3(f-1) through Tariff, Attachment K-Appendix, section (f-4).

(ii) PJM will calculate the revenue above cost for the pricing run for each Real-time Settlement Interval in accordance with the following equation:

$$(A \times B) - C$$

Where:

A = the resource's expected output level based on its resource parameters at the Real-time Price at the applicable pricing point;

B = the Real-time Price at the applicable pricing point; and

C = the sum of the resource's Real-time Energy Market offer integrated under the Final Offer for the resource's expected output level based on its resource parameters at the Real-time Price at the applicable pricing point.

(iii) PJM will calculate the revenue above cost for the dispatch run for each Real-time Settlement Interval in accordance with the following equation:

$$(\text{greater of A and B}) - (\text{lesser of C and D})$$

Where:

A = the product of the amount of megawatts of energy dispatched in the Real-time Energy Market dispatch run for the resource in that Real-time Settlement Interval and the Real-time Price at the applicable pricing point;

B = the product of the amount of megawatts of energy the resource actually provided in that Real-time Settlement Interval and the Real-time Price at the applicable pricing point;

C = the resource's Real-time Energy Market offer integrated under the Final Offer for the amount of megawatts dispatched in the Real-time Energy Market dispatch run;

D = the resource's Real-time Energy Market offer integrated under the Final Offer for the amount of megawatts the resource actually provided in that Real-time Settlement Interval.

(iv) The Dispatch Differential Lost Opportunity Cost credit shall equal the greater of (A) the difference between the revenue above cost based on the pricing run determined in subsection (f-5)(ii) and the revenue above cost based on the dispatch run determined in subsection (f-5)(iii) or (B) zero.

(v) For each hour in an Operating Day, the total cost of the Dispatch Differential Lost Opportunity Cost credits shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load ((a) net of operating Behind The Meter Generation, but not to be less than zero; and (b) excluding Direct Charging Energy) in the PJM Region, served under Network Transmission Service, in megawatt-hours; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Tariff, Attachment K-Appendix, section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(g) The sum of the foregoing credits in Tariff, Attachment K-Appendix, section 3.2.3(f-1) through Tariff, Attachment K-Appendix, section 3.2.3(f-4), 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 shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, shall be allocated and charged to each Market Participant based on their daily total of hourly deviations determined in accordance with the following equation:

$$\sum_h (A + B + C)$$

Where:

h = the hours in the applicable Operating Day;

A = For each Real-time Settlement Interval in an hour, the sum of the absolute value of the withdrawal deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy withdrawals (net of operating Behind The Meter Generation) in the Real-Time Energy Market, except as noted in subsection (h)(ii) below and in the PJM Manuals divided by the number of Real-time Settlement Intervals for that hour. The summation of each Real-time Settlement Interval's withdrawal deviation in an hour will be the Market Participant's total hourly withdrawal deviations. Market Participant bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to section 1.12 of this Schedule are not included in the determination of withdrawal deviations;

B = For each Real-time Settlement Interval in an hour, the sum of the absolute value of generation deviations (in MW and not including deviations in Behind The Meter Generation) as determined in subsection (o) divided by the number of Real-Time Settlement Intervals for that hour;

C = For each Real-time Settlement Interval in an hour, the sum of the absolute value of the injection deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy injections in the Real-Time Energy Market divided by the number of Real-time Settlement Intervals for that hour. The summation of the injection deviations for each Real-time Settlement Interval in an hour will be the Market Participant's total hourly injection deviations. The determination of injection deviations does not include generation resources.

The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with section 3.1A of this Schedule shall be used in determining the real-time withdrawal deviations, generation deviations and injection deviations used to calculate Operating Reserve under this subsection (e).

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

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

Deviations that occur within a single Zone shall be associated with the Eastern or Western Region, as defined in Section 3.2.3(q) of this Schedule, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with Section 3.2.3(q). Deviations at a hub shall be associated with the Eastern or Western Region if all the buses that define the hub are located in the region. Deviations at an Interface Pricing Point shall be associated with whichever region, the Eastern or Western Region, with which the majority of the buses that define that Interface Pricing Point are most closely electrically associated. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by buses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed for each Real-time Settlement Interval in accordance with the following provisions:

- (i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.
- (ii) Demand deviations will be assessed by comparing all day-ahead demand transactions, which include the components referenced in section 3.2.3(d) regarding the cost of Operating Reserves in the Day-ahead Energy Market, at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.
- (iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.
- (iv) Bilateral transactions inside the PJM Region, as defined in Operating Agreement, Schedule 1, section 1.7.10, will not be included in the determination of Supply or Demand deviations.

(i) At the end of each Operating Day, Market Sellers shall be credited 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 Dynamic Transfers 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 and greater than the Market Seller’s lowest

available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. 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 Real-time Settlement Intervals that the offer is economic divided by the megawatt hours of energy provided during the Real-time Settlement Intervals that the offer is economic. The Real-time Settlement Intervals that the offer is economic shall be: (i) the Real-time Settlement Intervals that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the Real-time Settlement Intervals in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any Real-time Settlement Intervals required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price for a market-based offer is greater than \$1,000/MWh and greater than the Market Seller's lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than \$1,000/MWh, the Market Seller shall receive credit for 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 below and in the PJM Manuals.

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

- (i) real-time economic minimum \leq 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.
- (ii) real-time economic maximum \geq 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

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

$$Ramp_Request_t = \frac{(Dispatchtarget_{t-1} - AOutput_{t-1})}{(LAtime_{t-1})}$$

$$RL_Desired_t = AOutput_{t-1} + (Ramp_Request_t * Case_Eff_time_{t-1})$$

where:

1. Dispatchtarget = Dispatch Signal for the previous approved Dispatch case
2. AOutput = Unit's achievable target MW at case solution time as defined in the PJM Manuals
3. LAtime = Dispatch look ahead time
4. Case_Eff_time = Time between signal changes
5. RL_Desired = Ramp-limited desired MW

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

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and dispatch signal, or if its %

off dispatch is ≤ 10 , or its Real-time Settlement Interval MWh is within 5% of the Real-time Settlement Interval ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined for each Real-time Settlement Interval in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – Day-Ahead MWh.
- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – dispatch LMP Desired MW.
- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – Ramp-Limited Desired MW.
- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and dispatch LMP Desired MWh for the Real-time Settlement Interval is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: Real time Settlement Interval MWh – dispatch LMP Desired MWh.
- If a resource is not following dispatch and its % Off Dispatch is $\leq 20\%$, balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh – Ramp-Limited Desired MW. If deviation value is within 5% of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.
- If a resource is not following dispatch and its % off Dispatch is $> 20\%$, balancing Operating Reserve deviations shall be assessed according to the following formula: Real time Settlement Interval MWh – dispatch LMP Desired MWh.
- If a resource is not following dispatch, and the resource has tripped, for the Real-time Settlement Interval the resource tripped and the Real-time Settlement Intervals it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: Real time Settlement Interval MWh – Day-Ahead MWh.
- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh - Day-Ahead MWh.

If a resource has a sum of the absolute value of generator deviations for an hour that is less than 5 MWh, then the resource shall not be assessed balancing Operating Reserve deviations for that hour.

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

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

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

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

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

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

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

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

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

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

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

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

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total

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

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

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

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

(r) Market Sellers that incur incremental operating costs for a generation resource that are either greater than \$1,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Schedule 2 of the Operating Agreement and PJM Manual 15, but are not verified at the time of dispatch of the resource under section 6.4.3 of this Schedule, or greater than \$2,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Schedule 2 of the Operating Agreement, and PJM Manual 15, will be eligible to receive credit for Operating Reserves upon review of the Market Monitoring Unit and the Office of the Interconnection, and approval of the Office of the Interconnection. Market Sellers must submit to the Office of the Interconnection and the Market Monitoring Unit all relevant documentation demonstrating the calculation of costs greater than \$2,000/MWh, and costs greater than \$1,000/MWh which were not verified at the time of dispatch of the resource under section 6.4.3 of this Schedule. The Office of the Interconnection must approve any Operating Reserve credits paid to a Market Seller under this subsection (r).

3.2.3A Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter

Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour (“Synchronized Reserve Obligation”), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b).

Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant with an hourly Synchronized Reserve Obligation shall be charged the pro rata share of the sum of the quantity of Synchronized Reserves provided in each Real-time Settlement Interval times the clearing price for all Real-time Settlement Intervals in the hour associated with that obligation.

(b) A resource 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, as described in 3.2.3A (c), with the exception of those Real-time Settlement Intervals in which the Non-Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone is not equal to zero. During such hours, Tier 1 Synchronized Reserve resources shall be compensated at the Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone for the lesser of the 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 in a Real-time Settlement Interval.

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 to a Synchronized Reserve Event in a Real-time Settlement Interval 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 in a Real-time Settlement Interval 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 an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval of the Operating Day. The hourly Synchronized Reserve Market Clearing Price shall be calculated as the 5-minute clearing price. Each 5-minute clearing price shall be calculated as the marginal cost of serving the next increment of demand for Synchronized Reserve in each Reserve Zone or Reserve Sub-zone, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve Requirement or Extended Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met in the pricing run, the 5-minute clearing price shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the sum of the Reserve Penalty Factors for the Synchronized Reserve Requirement and Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the 5-minute clearing price shall be the sum of the Reserve Penalty Factors for the Primary Reserve Requirement and the Synchronized Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

The Reserve Penalty Factor for the Synchronized Reserve Requirement shall be \$850/MWh.

The Reserve Penalty Factor for the Extended Synchronized Reserve Requirement shall be \$300/MWh.

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

(e) For each Real-time Settlement Interval and for determining the 5-minute Synchronized Reserve clearing price, the estimated unit-specific opportunity cost for a generation resource will be determined in accordance with the following equation:

$$(A \times B) + (C \times D)$$

Where

A = The Locational Marginal Price at the generation bus for the generation resource;

B = The megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer;

C = 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; and

D = The difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a resource 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 Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be in accordance with the following equation:

$$(A \times B) + (C \times D)$$

Where:

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;

B = The Locational Marginal Price at the generation bus of the generation resource;

C = 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; and

D = 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 Participant in excess of that Market Participant's Synchronized Reserve Obligation, the Tier 1 Synchronized Reserve that is not utilized to fulfill the Market Participant's obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

(h) Any amounts credited for Tier 2 Synchronized Reserve in a Real-time Settlement Interval in excess of the Synchronized Reserve Market Clearing Price in that Real-time Settlement Interval shall be allocated and charged to each Market Participant 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 a Real-time Settlement Interval than was estimated as needed at the time the Synchronized Reserve Market Clearing Price was calculated for that Real-time Settlement Interval 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) A generation resource or Demand Resource will be credited for the assigned and/or self-scheduled amount of Tier 2 Synchronized Reserve, less any applicable Tier 2 Synchronized Reserve shortfall, multiplied by the Synchronized Reserve Market Clearing Price for each Real-Time Settlement Interval, in which they were assigned and/or self-scheduled. In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled to provide Tier 2 Synchronized Reserve fails to provide the ~~PJM calculated expected response assigned or self-scheduled amount~~ of Tier 2 Synchronized Reserve in response to a Synchronized Reserve Event, the generation resource or Demand Resource will have a Tier 2 Synchronized Reserve shortfall. will be credited for Tier 2 Synchronized Reserve capacity in the amount that actually responded for The Tier 2 Synchronized Reserve shortfall amount will be the difference between the lesser of the assigned plus self-scheduled amount or the PJM-calculated expected response and the actual response provided. The PJM-calculated expected response is based on the energy dispatch signals and instructions of the Office of the Interconnection. The Tier 2 Synchronized Reserve shortfall amount is for all Real-time Settlement Intervals the generation resource or Demand Resource was assigned and/or self-scheduled Tier 2 Synchronized Reserve on the Operating Day during which the event occurred. The determination of the amount of Synchronized Reserve credited to a generation resource or Demand Resource shall be on an individual resource basis, not on an aggregate basis.

The resource shall refund payments received for Tier 2 Synchronized Reserve it failed to provide. For purposes of determining the amount of the payments to be refunded by a Market Participant, the Office of the Interconnection shall calculate the shortfall of Tier 2 Synchronized Reserve on an individual resource basis unless the Market Participant had multiple Demand Resources that were assigned or self-scheduled to provide Tier 2 Synchronized Reserve, in which case the shortfall will be determined on an aggregate basis. For performance determined on an aggregate basis, the response of any Demand Resource that provided more Tier 2 Synchronized Reserve than it was assigned or self-scheduled to provide will be used to offset the performance of other Demand Resources that provided less Tier 2 Synchronized Reserve than they were assigned or self-scheduled to provide during a Synchronized Reserve Event, as

calculated in the PJM Manuals. The determination of a Market Participant's aggregate response shall not be taken into consideration in the determination of the amount of Tier 2 Synchronized Reserve credited to each individual Demand Resource.

The amount refunded shall be determined by multiplying the Synchronized Reserve Market Clearing Price by the amount of the shortfall of Tier 2 Synchronized Reserve, measured in megawatts, for all intervals the resource was assigned or self-scheduled to provide Tier 2 Synchronized Reserve for a period of time immediately preceding the Synchronized Reserve Event equal to the lesser of the average number of days between Synchronized Reserve Events, or the number of days since the resource last failed to provide the amount of Tier 2 Synchronized Reserve it was assigned or self-scheduled to provide in response to a Synchronized Reserve Event. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following January 1. The refunded charges shall be allocated as credits to Market Participants based on its pro rata share of the Synchronized Reserve Obligation megawatts less any Tier 1 Synchronized Reserve applied to its Synchronized Reserve Obligation in the hour(s) of the Synchronized Reserve Event for the Reserve Sub-zone or Reserve Zone, except that Market Participants that incur a refund obligation and also have an applicable Synchronized Reserve Obligation during the hour(s) of the Synchronized Reserve Event shall not be included in the allocation of such refund credits. If the event spans multiple hours, the refund credits will be prorated hourly based on the duration of the event within each clock hour.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or 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 or increased by the amount the megawatt output of the generation resource ~~falls below~~ differs from 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 but will be capped. If the generation resource has an assignment and the PJM-calculated expected response is greater than the assigned, then the megawatt output will be capped at the difference of the PJM-calculated expected response and the assigned. If the generation resource has no assignment, then the megawatt output will be capped at the PJM-calculated expected response. The PJM-calculated expected response is based on the energy dispatch signals and instructions of the Office of the Interconnection. 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 Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant with an hourly Non-Synchronized Reserve Obligation shall be charged the pro rata share of the sum of the quantity of Non-Synchronized Reserves provided in each Real-time Settlement Interval times the clearing price for all Real-time Settlement Intervals in the hour associated with that obligation.

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

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval of the Operating Day. The Non-Synchronized Reserve Market Clearing Price shall be calculated as the 5-minute clearing price. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve Requirement or Extended Primary Reserve Requirement. When the Primary Reserve Requirement or Extended Primary Reserve Requirement in a Reserve Zone

or Reserve Sub-zone cannot be met in the pricing run at a price less than or equal to the applicable Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the 5-minute clearing price shall be the Reserve Penalty Factor for the Primary Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

The Reserve Penalty Factor for the Synchronized Reserve Requirement shall be \$850/MWh.

The Reserve Penalty Factor for the Extended Primary Reserve Requirement shall be \$300/MWh.

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

(d) For each Real-time Settlement Interval and for determining the 5-minute Non-Synchronized Reserve clearing price, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves will be determined in accordance with the following equation:

$$(A \times B) - C$$

Where:

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;

B = The Locational Marginal Price at the generation bus for the generation resource; and

C = The applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a resource 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 Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Non-Synchronized Reserve and shall be in accordance with the following equation:

$$(A \times B) - C$$

Where:

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;

B = The Locational Marginal Price at the generation bus for the generation resource; and

C = The applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

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

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

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

3.2.3A.01 Day-ahead Scheduling Reserves.

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

bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

(b) A Day-ahead Scheduling Reserves Resource that receives a Day-ahead Scheduling Reserves schedule pursuant to subsection (a) of this section shall be paid the hourly Day-ahead Scheduling Reserves Market clearing price, as determined in the day-ahead pricing run set forth in Tariff, Attachment K-Appendix, section 2.6, for the cleared megawatt quantity of Day-ahead Scheduling Reserves 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 hourly credits paid to Day-ahead Scheduling Reserves Resources satisfying the Base Day-ahead Scheduling Reserves Requirement (“Base Day-ahead Scheduling Reserves credits”) shall equal the ratio of the Base Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement, multiplied by the total credits paid to Day-ahead Scheduling Reserves Resources, and are allocated as Base Day-ahead Scheduling Reserves charges per paragraph (i) below. The hourly credits paid to Day-ahead Scheduling Reserve Resources satisfying the Additional Day-ahead Scheduling Reserve Requirement (“Additional Day-ahead Scheduling Reserves credits”) shall equal the ratio of the Additional Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement, multiplied by the total credits paid to Day-ahead Scheduling Reserves Resources and are allocated as Additional Day-ahead Scheduling Reserves charges per paragraph (ii) below.

- (i) A Market Participant’s Base Day-ahead Scheduling Reserves charge is equal to the ratio of the Market Participant’s hourly obligation to the total hourly obligation of all Market Participants in the PJM Region, multiplied by the Base Day-ahead Scheduling Reserves credits. The hourly obligation for each Market Participant is a megawatt representation of the portion of the Base Day-ahead Scheduling Reserves credits that the Market Participant is responsible for paying to PJM. The hourly obligation is equal to the Market Participant’s load ratio share of the total megawatt volume of Base Day-ahead Scheduling Reserves resources (described below), based on the Market Participant’s total hourly load (net of operating Behind The Meter Generation, but not to be less than zero) to the total hourly load of all Market Participants in the PJM Region. The total megawatt volume of Base Day-ahead Scheduling Reserves resources equals the ratio of the Base Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement multiplied by the total volume of Day-ahead Scheduling Reserves megawatts paid pursuant to paragraph (c) of this section. A Market Participant’s hourly Day-ahead Scheduling Reserves obligation can be further adjusted by any Day-ahead Scheduling Reserve bilateral transactions.
- (ii) Additional Day-ahead Scheduling Reserves credits shall be charged hourly to Market Participants that are net purchasers in the Day-ahead Energy Market based on its positive demand difference ratio share. The positive demand difference for each Market Participant is the difference between its real-time load (net of operating Behind The Meter Generation, but not to be less than zero) and cleared Demand Bids in the Day-ahead Energy Market, net of cleared Increment Offers and cleared Decrement Bids in the Day-ahead Energy Market, when such value is positive. Net purchasers in the Day-ahead Energy Market are those Market

Participants that have cleared Demand Bids plus cleared Decrement Bids in excess of its amount of cleared Increment Offers in the Day-ahead Energy Market. If there are no Market Participants with a positive demand difference, the Additional Day-ahead Scheduling Reserves credits are allocated according to paragraph (i) above.

(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 real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than \$0.00. This equation is represented as $(A*B) - C$.

(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 for each Real-time Settlement Interval, limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the

Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(e) At the end of each Operating Day, where the active energy output 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 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 in an amount equal to $\{(AG - LMPDMW) \times (UB - URTLMP)\}$ where:

AG equals the actual 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 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 lesser of the Final Offer or Committed Offer;

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

where $UB - URTLMP$ shall not be negative.

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

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a

mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market Participant 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 Synchronized Reserve Market Clearing Price for each Real-time Settlement Interval a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generating unit's bus, (C) the generating unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generating resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generating unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of the Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

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

whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

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

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

3.2.3C Synchronous Condensing for Post-Contingency Operation.

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

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve.

At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Synchronized Reserve Market Clearing Price for each applicable interval a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's applicable interval cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the applicable interval 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 for the Synchronized Reserve Requirement and Primary Reserve Requirement, provided that the Emergency energy is needed to meet demand in the PJM Region.
- (b) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each applicable interval of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.
- (c) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each applicable interval of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.
- (d) The net costs or net revenues associated with sales or purchases of energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each applicable interval of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

- (a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Participant in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Participant's internal accounting.
- (b) If deliveries to a Market Participant that has PJM Interchange meters in accordance with 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 Participant, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market

Participant and the unmetered Market Participant specified by them to the Office of the Interconnection.

1.11 Real-time Dispatch.

The Office of the Interconnection shall determine the least cost security constrained economic dispatch and send dispatch targets for each resource to Market Participants. The least cost security constrained economic dispatch is the least costly means of serving load and meeting reserve requirements at different locations in the PJM Region based on forecasted operating conditions on the power grid (including transmission constraints on external coordinated flowgates to the extent provided by Operating Agreement, Schedule 1, section 1.7.6) as described in the PJM Manuals and on the offers for energy and ancillary services at which Market Sellers have entered as described by Operating Agreement, Schedule 1, section 1.10 and Operating Agreement, Schedule 1, section 2.4 and on offers by Economic Load Response Participants to reduce demand that qualify to set Locational Marginal Prices in the PJM Interchange Energy Market.

(a) To determine actual operating conditions on the power grid in the PJM Region (including transmission constraints on external coordinated flowgates to the extent provided by Operating Agreement, Schedule 1, section 1.7.6), the Office of the Interconnection shall 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 as an input into the real-time security constrained economic dispatch. The computer model employed for this purpose, referred to as the State Estimator program, is a standard industry tool and is described in section 1.11A below. The State Estimator solution used by the real-time security constrained economic dispatch will be used to obtain information regarding the output of generation supplying energy to the PJM Region, loads at buses in the PJM Region, transmission losses, and power flows on binding transmission constraints.

(b) The Office of the Interconnection shall execute real-time security constrained economic dispatch for each five (5) minute target time, unless the Office of the Interconnection is unable to generate real-time security constrained economic dispatch solutions due to operational or technical issues, including but not limited to those described in the PJM Manuals. Each execution of the real-time security constrained economic dispatch shall result in several solutions, taking into consideration different operational scenarios.

(c) The Office of the Interconnection shall approve the applicable real-time security constrained economic dispatch solution for each five (5) minute target time, unless the Office of the Interconnection is unable to approve a real-time security constrained economic dispatch solution for the applicable target time due to a failure of the real-time security constrained economic dispatch program or other operational reasons. In such situations, either the most recently approved real-time security constrained economic dispatch solution shall persist, or the Office of the Interconnection shall manually dispatch the system.

1.11A 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 performing the security constrained economic dispatch of the system, 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. The 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 buses for which real-time information is unavailable. The Office of the Interconnection shall obtain the latest State Estimator solution each time a new security constrained economic dispatch is executed, 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 transmission facilities as defined in the PJM Manuals.

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 or self-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 or self-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.

As part of the real-time security constrained economic dispatch calculation, the Office of the Interconnection shall use submitted ramp rates to calculate the next dispatch point.

As part of the calculation, the Office of the Interconnection shall estimate the initial state of each generation resource based on its previous dispatch signal and the most recent State Estimator output. In the event the Office of the Interconnection is unable to approve a real-time security constrained economic dispatch solution for a period of time, due to a failure of the real-time

security constrained economic dispatch program or other operational reasons, the most recent State Estimator shall be used as the initial state. This evaluation methodology is calculated for all online dispatchable resources for each market solution in accordance with the PJM Manuals.

(a) The Office of the Interconnection shall implement the dispatch of energy from pool-scheduled resources with limited energy by direct request, by following the Day-ahead Market clearing, or by following the direct request of the Market Seller, subject to the Office of the Interconnection's determination of actions necessary to maintain reliability.

(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 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 upon receipt.

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 and Reserve Sub-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 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) Synchronized Reserve Events will be initiated by the Office of the Interconnection by approving the latest solved intelligent reserve deployment (IRD) case in the real-time security constrained economic dispatch application. When initiating a Synchronized Reserve Event, the Office of the Interconnection shall dispatch generation resources and/or direct the deployment of Demand Resources for Synchronized Reserve by transmitting Synchronized Reserve instructions to generation resources and Demand Resources through approval of the latest available IRD case solution in the real-time security constrained economic dispatch application 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. In the event the IRD case is not available (as described in Tariff, Attachment K-Appendix, Sections 1.11(b) and (c)), manual Synchronized Reserve deployment will be utilized, in accordance with PJM Manuals.

1.11.4B Non-Synchronized Reserve.

(a) A Market Buyer may satisfy its Non-Synchronized Reserve Obligation from its own generation 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. PJMSettlement shall be the Counterparty to the purchases and sales of Non-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-supply of generation resources by a Market Buyer to satisfy its Non-Synchronized Reserve Obligation.

(b) The Office of the Interconnection shall obtain Non-Synchronized Reserve from the least-cost alternatives available from either pool-scheduled generation resources as needed to ensure the Primary Reserve requirement of each Reserve Zone and Reserve Sub-zone of the PJM Region not otherwise satisfied by the Market Buyers. Resources eligible to sell Non-Synchronized Reserve shall be selected to provide Non-Synchronized Reserve on the basis of each generation 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 not providing energy because they are providing Non-Synchronized Reserve shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price

at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(c) The Office of the Interconnection shall dispatch generation resources for Non-Synchronized Reserve by sending Non-Synchronized Reserve instructions to generation 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.

3.2 Market Settlements.

If a dollar-per-MW-hour value is applied in a calculation under this section 3.2 where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW hour value is divided by the number of Real-time Settlement Intervals in the hour.

3.2.1 Spot Market Energy.

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

(b) Each Market Participant shall be charged for all of its Market Participant Energy Withdrawals scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price to be served in the PJM Interchange Energy Market.

(c) Each Market Participant shall be paid for all of its Market Participant Energy Injections scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price to be delivered to the PJM Interchange Energy Market.

(d) For each Day-ahead Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its Market Participant Energy Withdrawals scheduled times the Day-ahead System Energy Price and the sum of its Market Participant Energy Injections scheduled times the Day-ahead System Energy Price.

(e) For each Real-time Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its real-time Market Participant Energy Withdrawals less its scheduled Market Participant Energy Withdrawals times the Real-time System Energy Price and the sum of its real-time Market Participant Energy Injections less scheduled Market Participant Energy Injections times the Real-time System Energy Price. The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with section 3.1A of this Schedule shall be used in determining the real-time Market Participant Energy Withdrawals and Market Participant Energy Injections used to calculate Spot Market Energy charges under this subsection (e).

(f) For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the megawatts of real-time energy injections to be delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region

3.2.2 Regulation.

(a) Each Market Participant that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). A Market Participant with an hourly Regulation Obligation shall be charged the pro rata share of the sum of the Regulation market performance clearing price credits and Regulation market capability clearing price credits for the Real-time Settlement Intervals in an hour.

Regulation Charge = Hourly Regulation Obligation Share * (sum of the Real-time Settlement Interval Regulation credits in an hour)

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

(c) The total Regulation market-clearing price in each Regulation Zone shall be determined in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval. The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the

generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

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

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

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

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

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

(e) In determining the credit under subsection (b) to a Market Participant selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for (1) each Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Regulation, and (2) the last three Real-time Settlement Intervals of the preceding shoulder hour and the first three Real-time Settlement Intervals of the following shoulder hour in accordance with the PJM Manuals and below.

The unit-specific opportunity cost incurred during the Real-time Settlement Interval 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 each of the preceding three Real-time Settlement Intervals of the 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 Real-time Settlement Interval in order to provide Regulation and the resource's expected output in each of the preceding three Real-time Settlement Intervals of the shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in each of the preceding three Real-time Settlement Intervals of the 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 Real-time Settlement Interval) in the PJM Interchange Energy Market, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during each of the following three Real-time Settlement Intervals of the 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 Real-time Settlement Interval in order to provide Regulation and the resource's expected output in each of the following three Real-time Settlement Intervals of the shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in each of the following three Real-time Settlement Intervals of the 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 all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Market Participant in a Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

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

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

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

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

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

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

(j) The Office of the Interconnection shall calculate a unit-specific benefits factor for each of the dynamic Regulation signal and traditional Regulation signal in accordance with the PJM Manuals. Each resource shall be assigned a unit-specific benefits factor based on their

order in the merit order stack for the applicable Regulation signal. The unit-specific benefits factor is the point on the benefits factor curve that aligns with the last megawatt, adjusted by historical performance, that resource will add to the dynamic resource stack. Resources following the dynamic Regulation signal which have a unit-specific benefits factor less than 0.1 will not be considered for the purposes of committing resources. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

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

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

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

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

where δ is delay.

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

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

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

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

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

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

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

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

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

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

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

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

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region multiplied by the historic accuracy score of the resource and multiplied by the unit-specific benefits factor for which the capability cost-based offer plus the performance cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The three-pivotal supplier test will apply on a Regulation supplier basis (i.e. not a resource by resource basis) and only the Regulation suppliers that fail the three-pivotal supplier test will have their Regulation offers capped. A Regulation supplier for the purposes of this section includes corporate affiliates. Regulation from resources controlled by a Regulation supplier or its affiliates, whether by contract with unaffiliated third parties or otherwise, will be included as Regulation of that Regulation supplier. Regulation provided by resources owned by a Regulation supplier but controlled by an unaffiliated third party, whether by contract or otherwise, will be included as Regulation of that third party.

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

a third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the applicable offer for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that 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. PJMSettlement shall be the Counterparty to the purchases and sales of Operating Reserve in the PJM Interchange Energy Market.

(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 Costs and No-load Costs and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. PJM shall also (i) determine whether any resources were scheduled in the Day-ahead Energy Market to provide Black Start service, Reactive Services or transfer interface control during the Operating Day because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day in order to minimize the total cost of Operating Reserves associated with the provision of such services and reflect the most accurate possible expectation of real-time operating conditions in the day-ahead model, which resources would not have otherwise been committed in the day-ahead security-constrained dispatch and (ii) report on the day following the Operating Day the megawatt quantities scheduled in the Day-ahead Energy Market for the above-enumerated purposes for the entire RTO.

Except as provided in Section 3.2.3(n), if the total offered price for Start-up Costs (shutdown costs for Demand Resources) and No-load Costs and energy summed over all Day-ahead Settlement Intervals exceeds the total value summed over all Day-ahead Settlement Intervals, the difference shall be credited to the Market Seller as a day-ahead Operating Reserve credit.

However, for the Day-ahead Settlement Intervals in which the resource is scheduled to provide energy in the Operating Day and the resource actually provides energy in at least one Real-time Settlement Interval in an hour that corresponds to such scheduled Day-ahead Settlement Intervals, a resource's day-ahead Operating Reserve credit shall be reduced by the greater of zero or the difference of the resource's Day-ahead Operating Reserve Target and the Balancing Operating Reserve Target, as determined below.

A resource's Day-ahead Operating Reserve Target shall be determined in accordance with the following equation:

$$(A + B) - C$$

Where:

A = Start-up Costs

B = the sum of day-ahead No-load Costs and energy over the applicable Real-time Settlement Intervals that correspond with Day-ahead Settlement Intervals in which the resource is scheduled. The day-ahead No-load Costs and energy are divided by twelve to determine the cost for each Real-time Settlement Interval.

C = the sum of the day-ahead revenues calculated for each Real-time Settlement Interval that corresponds with a Day-ahead Settlement Interval in which the resource is scheduled, where the day-ahead revenue for each such Real-time Settlement Interval equals the product of the megawatt amount of energy scheduled in the Day-ahead Energy Market and the Day-ahead Price at the applicable pricing point for the resource divided by twelve.

A resource's Balancing Operating Reserve Target shall be determined in accordance with the following equation:

$$D - (E + F)$$

Where:

D = the sum of Start-up Costs and No-load Costs and the incremental cost of energy summed over all Real-time Settlement Intervals that correspond to the Day-ahead Settlement Intervals in which the resource was scheduled;

E = [(the megawatt amount of energy provided in the Real-time Energy Market minus the megawatt amount of energy scheduled in the Day-ahead Energy Market) multiplied by the Real-time Price at the applicable pricing point for the resource] plus the sum of the day-ahead revenues as determined in part C of the above formula for determining the Day-ahead Operating Reserve Target, summed over the applicable Real-time Settlement Intervals; and

F = the sum of all revenues earned for providing Day-ahead Scheduling Reserves, Synchronized Reserves, Non-Synchronized Reserves, and Reactive Services over the applicable Real-time Settlement Intervals.

The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this section 3.2.3(b) to real-time deviations or real-time load share plus exports, pursuant to Operating Agreement, Schedule 1, section 3.2.3(p), 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.

(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), accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day and accepted Up-to Congestion Transactions in the Day-ahead Energy Market in megawatt-hours for the Operating Day at the sink of the transaction; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside such area pursuant to Section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load (net of operating Behind The Meter Generation) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following Segments: 1) the greater of their day-ahead schedules and minimum run time specified at the time of commitment (minimum

down time specified at the time of commitment for Demand Resources); and 2) any block of Real-time Settlement Intervals the resource operates at PJM's direction in excess of the greater of its day-ahead schedule and minimum run time specified at the time of commitment (minimum down time specified at the time of commitment for 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 specified at the time of commitment (minimum down time specified at the time of commitment for Demand Resources) and Segment 2 will include the remainder of the contiguous Real-time Settlement Intervals when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

A Generation Capacity Resource that operates outside of its unit-specific parameters will not receive Operating Reserve Credits nor be made whole for such operation when not dispatched by the Office of the Interconnection, unless the Market Seller of the Generation Capacity Resource can justify to the Office of the Interconnection that operation outside of such unit-specific parameters was the result of an actual constraint. Such Market Seller shall provide to the Market Monitoring Unit and the Office of the Interconnection its request to receive Operating Reserve Credits and/or to be made whole for such operation, along with documentation explaining in detail the reasons for operating its resource outside of its unit-specific parameters, within thirty calendar days following the issuance of billing statement for the Operating Day. The Market Seller shall also respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection. The Market Monitoring Unit shall evaluate such request for compensation and provide its determination of whether there was an exercise of market power to the Office of the Interconnection by no later than twenty-five calendar days after receiving the Market Seller's request for compensation. The Office of the Interconnection shall make its determination whether the Market Seller justified that it is entitled to receive Operating Reserve Credits and/or be made whole for such operation of its resource for the day(s) in question, by no later than thirty calendar days after receiving the Market Seller's request for compensation.

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 Tariff, Attachment K-Appendix, section 3.2.3(f) and the parallel provision of Operating Agreement, Schedule 1, section 3.2.3(f); or 2) the resource submits a request for a risk premium to the Market Monitoring Unit under the procedures specified in Tariff, Attachment M – Appendix, section II.B. A nuclear generation resource (i) must submit a risk premium consistent with its agreement under such process, or, (ii) if it has not agreed with the Market Monitoring Unit on an appropriate risk premium, may submit its own determination of an appropriate risk premium to the Office of the Interconnection, subject to acceptance by the Office of the Interconnection, with or without prior approval from the Commission.

Credits received pursuant to this section shall be equal to the positive difference between a resource's Total Operating Reserve Offer, and the total value of the resource's energy in the

Day-ahead Energy Market plus any credit or change for quantity deviations, at PJM dispatch direction (excluding quantity deviations caused by an increase in the Market Seller's Real-time Offer), from the Day-ahead Energy Market during the Operating Day at the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for Segment 2 shall exclude start up (shutdown costs for Demand Resources) costs for generation resources.

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

Synchronized Reserve, Non-Synchronized Reserve, and Real-time Settlement Interval share of the 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 Real-time Settlement Interval(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 Real-time Settlement Interval the unit operates in condensing and generation mode.

(f) A Market Seller of a unit not defined in subsection (f-1), (f-2), or (f-4) hereof (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than \$0.00. This equation is represented as $(A*B) - C$.

(f-1) With the exception of Market Sellers of Flexible Resources that submit a Real-time Offer greater than their resource's Committed Offer in the Day-ahead Energy Market, a Market Seller of a Flexible Resource shall be compensated for lost opportunity cost, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if either of the following conditions occur:

- (i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described in section 3.2.3 (f).
- (ii) If the unit is scheduled to produce energy in the Day-ahead Energy Market for a Day-ahead Settlement Interval, but the unit is not called on by the Office of the Interconnection and does not operate in the corresponding Real-time Settlement Interval(s), then the Market Seller shall be credited in an amount equal to the higher of:
 - 1) the product of (A) the amount of megawatts committed in the Day-ahead Energy Market for the generating unit, and (B) the Real-time Price at the generation bus for the generating unit, minus the sum of (C) the Total Lost Opportunity Cost Offer plus No-load Costs, plus (D) the Start-up Cost, divided by the Real-time Settlement Intervals committed for each set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market. This equation is represented as $(A*B) - (C+D)$. The startup cost, (D), shall be excluded from this calculation if the unit operates in real time following the Office of the Interconnection's direction during any portion of the set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market, or
 - 2) the Real-time Price at the unit's bus minus the Day-ahead Price at the unit's bus, multiplied by the number of megawatts committed in the Day-ahead Energy Market for the generating unit.

Market Sellers of Flexible Resources that submit a Real-time Offer greater than their resource's Committed Offer in the Day-ahead Energy Market shall not be eligible to receive compensation for lost opportunity costs under any applicable provisions of Schedule 1 of this Agreement.

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

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output

due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-4) A Market Seller of a wind generating unit that is pool-scheduled or self-scheduled, has SCADA capability to transmit and receive instructions from the Office of the Interconnection, has provided data and established processes to follow PJM basepoints pursuant to the requirements for wind generating units as further detailed in this Agreement, the Tariff and the PJM Manuals, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the , real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than \$0.00. This equation is represented as $(A*B) - C$.

(f-5) (i) A Market Seller of a pool-scheduled resource or a dispatchable self-scheduled resource shall receive Dispatch Differential Lost Opportunity Cost credits as calculated under subsection (iv) below if the resource is dispatched to provide energy in the Real-time Energy Market, provided such resource is not committed to provide real-time ancillary services (Regulation, reserves, reactive service) or instructed to reduce or suspend output due to a transmission constraint or other reliability issue pursuant to Operating Agreement, Schedule 1, section 3.2.3(f-1) through Operating Agreement, Schedule 1, section (f-4).

(ii) PJM will calculate the revenue above cost for the pricing run for each Real-time Settlement Interval in accordance with the following equation:

$$(A \times B) - C$$

Where:

A = the resource's expected output level based on its resource parameters at the Real-time Price at the applicable pricing point;

B = the Real-time Price at the applicable pricing point; and

C = the sum of the resource's Real-time Energy Market offer integrated under the Final Offer for the resource's expected output level based on its resource parameters at the Real-time Price at the applicable pricing point.

(iii) PJM will calculate the revenue above cost for the dispatch run for each Real-time Settlement Interval in accordance with the following equation:

$$(\text{greater of A and B}) - (\text{lesser of C and D})$$

Where:

A = the product of the amount of megawatts of energy dispatched in the Real-time Energy Market dispatch run for the resource in that Real-time Settlement Interval and the Real-time Price at the applicable pricing point;

B = the product of the amount of megawatts of energy the resource actually provided in that Real-time Settlement Interval and the Real-time Price at the applicable pricing point;

C = the resource's Real-time Energy Market offer integrated under the Final Offer for the amount of megawatts dispatched in the Real-time Energy Market dispatch run;

D = the resource's Real-time Energy Market offer integrated under the Final Offer for the amount of megawatts the resource actually provided in that Real-time Settlement Interval.

(iv) The Dispatch Differential Lost Opportunity Cost credit shall equal the greater of (A) the difference between the revenue above cost based on the pricing run determined in subsection (f-5)(ii) and the revenue above cost based on the dispatch run determined in subsection (f-5)(iii) or (B) zero.

(v) For each hour in an Operating Day, the total cost of the Dispatch Differential Lost Opportunity Cost credits shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load ((a) net of operating Behind The Meter Generation, but not to be less than zero; and (b) excluding Direct Charging Energy) in the PJM Region, served under Network Transmission Service, in megawatt-hours; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Operating Agreement, Schedule 1, section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(g) The sum of the foregoing credits in Operating Agreement, Schedule 1, section 3.2.3(f-1) through Operating Agreement, Schedule 1, section 3.2.3(f-4), 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 shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, shall be allocated and charged to each Market Participant based on their daily total of hourly deviations determined in accordance with the following equation:

$$\sum_h (A + B + C)$$

Where:

h = the hours in the applicable Operating Day;

A = For each Real-time Settlement Interval in an hour, the sum of the absolute value of the withdrawal deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy withdrawals (net of operating Behind The Meter Generation) in the Real-Time Energy Market, except as noted in subsection (h)(ii) below and in the PJM Manuals divided by the number of Real-time Settlement Intervals for that hour. The summation of each Real-time Settlement Interval's withdrawal deviation in an hour will be the Market Participant's total hourly withdrawal deviations. Market Participant bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to section 1.12 of this Schedule are not included in the determination of withdrawal deviations;

B = For each Real-time Settlement Interval in an hour, the sum of the absolute value of generation deviations (in MW and not including deviations in Behind The Meter Generation) as determined in subsection (o) divided by the number of Real-Time Settlement Intervals for that hour;

C = For each Real-time Settlement Interval in an hour, the sum of the absolute value of the injection deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy injections in the Real-Time Energy Market divided by the number of Real-time Settlement Intervals for that hour. The summation of the injection deviations for each Real-time Settlement Interval in an hour will be the Market Participant's total hourly injection deviations. The determination of injection deviations does not include generation resources.

The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with section 3.1A of this Schedule shall be used in determining the real-time withdrawal deviations, generation deviations and injection deviations used to calculate Operating Reserve under this subsection (e).

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

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

Deviations that occur within a single Zone shall be associated with the Eastern or Western Region, as defined in Section 3.2.3(q) of this Schedule, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with Section 3.2.3(q). Deviations at a hub shall be associated with the Eastern or Western Region if all the buses that define the hub are located in the region. Deviations at an Interface Pricing Point shall be associated with whichever region, the Eastern or Western Region, with which the majority of the buses that define that Interface Pricing Point are most closely electrically associated. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by buses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed for each Real-time Settlement Interval in accordance with the following provisions:

- (i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.
- (ii) Demand deviations will be assessed by comparing all day-ahead demand transactions, which include the components referenced in section 3.2.3(d) regarding the cost of Operating Reserves in the Day-ahead Energy Market, at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.
- (iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.
- (iv) Bilateral transactions inside the PJM Region, as defined in Operating Agreement, Schedule 1, section 1.7.10, will not be included in the determination of Supply or Demand deviations.

(i) At the end of each Operating Day, Market Sellers shall be credited 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 Dynamic Transfers 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 and greater than the Market Seller’s lowest

available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. 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 Real-time Settlement Intervals that the offer is economic divided by the megawatt hours of energy provided during the Real-time Settlement Intervals that the offer is economic. The Real-time Settlement Intervals that the offer is economic shall be: (i) the Real-time Settlement Intervals that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the Real-time Settlement Intervals in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any Real-time Settlement Intervals required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price for a market-based offer is greater than \$1,000/MWh and greater than the Market Seller's lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than \$1,000/MWh, the Market Seller shall receive credit for 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 below and in the PJM Manuals.

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

- (i) real-time economic minimum \leq 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.
- (ii) real-time economic maximum \geq 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

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

$$Ramp_Request_t = \frac{(Dispatchtarget_{t-1} - AOutput_{t-1})}{(LAtime_{t-1})}$$

$$RL_Desired_t = AOutput_{t-1} + (Ramp_Request_t * Case_Eff_time_{t-1})$$

where:

1. Dispatchtarget = Dispatch Signal for the previous approved Dispatch case
2. AOutput = Unit's achievable target MW at case solution time as defined in the PJM Manuals
3. LAtime = Dispatch look ahead time
4. Case_Eff_time = Time between signal changes
5. RL_Desired = Ramp-limited desired MW

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

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and dispatch signal, or if its %

off dispatch is ≤ 10 , or its Real-time Settlement Interval MWh is within 5% of the Real-time Settlement Interval ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined for each Real-time Settlement Interval in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – Day-Ahead MWh.
- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – dispatch LMP Desired MW.
- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – Ramp-Limited Desired MW.
- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and dispatch LMP Desired MWh for the Real-time Settlement Interval is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: Real time Settlement Interval MWh – dispatch LMP Desired MWh.
- If a resource is not following dispatch and its % Off Dispatch is $\leq 20\%$, balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh – Ramp-Limited Desired MW. If deviation value is within 5% of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.
- If a resource is not following dispatch and its % off Dispatch is $> 20\%$, balancing Operating Reserve deviations shall be assessed according to the following formula: Real time Settlement Interval MWh – dispatch LMP Desired MWh.
- If a resource is not following dispatch, and the resource has tripped, for the Real-time Settlement Interval the resource tripped and the Real-time Settlement Intervals it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: Real time Settlement Interval MWh – Day-Ahead MWh.
- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh - Day-Ahead MWh.

If a resource has a sum of the absolute value of generator deviations for an hour that is less than 5 MWh, then the resource shall not be assessed balancing Operating Reserve deviations for that hour.

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

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

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

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

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

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

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

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

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

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

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

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

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total

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

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

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

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

(r) Market Sellers that incur incremental operating costs for a generation resource that are either greater than \$1,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Schedule 2 of the Operating Agreement and PJM Manual 15, but are not verified at the time of dispatch of the resource under section 6.4.3 of this Schedule, or greater than \$2,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Schedule 2 of the Operating Agreement, and PJM Manual 15, will be eligible to receive credit for Operating Reserves upon review of the Market Monitoring Unit and the Office of the Interconnection, and approval of the Office of the Interconnection. Market Sellers must submit to the Office of the Interconnection and the Market Monitoring Unit all relevant documentation demonstrating the calculation of costs greater than \$2,000/MWh, and costs greater than \$1,000/MWh which were not verified at the time of dispatch of the resource under section 6.4.3 of this Schedule. The Office of the Interconnection must approve any Operating Reserve credits paid to a Market Seller under this subsection (r).

3.2.3A Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter

Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour (“Synchronized Reserve Obligation”), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b).

Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant with an hourly Synchronized Reserve Obligation shall be charged the pro rata share of the sum of the quantity of Synchronized Reserves provided in each Real-time Settlement Interval times the clearing price for all Real-time Settlement Intervals in the hour associated with that obligation.

(b) A resource 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, as described in 3.2.3A (c), with the exception of those Real-time Settlement Intervals in which the Non-Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone is not equal to zero. During such hours, Tier 1 Synchronized Reserve resources shall be compensated at the Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone for the lesser of the 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 in a Real-time Settlement Interval.

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 to a Synchronized Reserve Event in a Real-time Settlement Interval 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 in a Real-time Settlement Interval 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 an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval of the Operating Day. The hourly Synchronized Reserve Market Clearing Price shall be calculated as the 5-minute clearing price. Each 5-minute clearing price shall be calculated as the marginal cost of serving the next increment of demand for Synchronized Reserve in each Reserve Zone or Reserve Sub-zone, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve Requirement or Extended Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met in the pricing run, the 5-minute clearing price shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the sum of the Reserve Penalty Factors for the Synchronized Reserve Requirement and Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the 5-minute clearing price shall be the sum of the Reserve Penalty Factors for the Primary Reserve Requirement and the Synchronized Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

The Reserve Penalty Factor for the Synchronized Reserve Requirement shall be \$850/MWh.

The Reserve Penalty Factor for the Extended Synchronized Reserve Requirement shall be \$300/MWh.

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

(e) For each Real-time Settlement Interval and for determining the 5-minute Synchronized Reserve clearing price, the estimated unit-specific opportunity cost for a generation resource will be determined in accordance with the following equation:

$$(A \times B) + (C \times D)$$

Where

A = The Locational Marginal Price at the generation bus for the generation resource;

B = The megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer;

C = 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; and

D = The difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a resource 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 Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be in accordance with the following equation:

$$(A \times B) + (C \times D)$$

Where:

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;

B = The Locational Marginal Price at the generation bus of the generation resource;

C = 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; and

D = 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 Participant in excess of that Market Participant's Synchronized Reserve Obligation, the Tier 1 Synchronized Reserve that is not utilized to fulfill the Market Participant's obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

(h) Any amounts credited for Tier 2 Synchronized Reserve in a Real-time Settlement Interval in excess of the Synchronized Reserve Market Clearing Price in that Real-time Settlement Interval shall be allocated and charged to each Market Participant 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 a Real-time Settlement Interval than was estimated as needed at the time the Synchronized Reserve Market Clearing Price was calculated for that Real-time Settlement Interval 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) A generation resource or Demand Resource will be credited for the assigned and/or self-scheduled amount of Tier 2 Synchronized Reserve, less any applicable Tier 2 Synchronized Reserve shortfall, multiplied by the Synchronized Reserve Market Clearing Price for each Real-Time Settlement Interval, in which they were assigned and/or self-scheduled. In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled to provide Tier 2 Synchronized Reserve fails to provide the ~~PJM calculated expected response assigned or self-scheduled amount~~ of Tier 2 Synchronized Reserve in response to a Synchronized Reserve Event, the generation resource or Demand Resource will have a Tier 2 Synchronized Reserve shortfall. will be credited for Tier 2 Synchronized Reserve capacity in the amount that actually responded for The Tier 2 Synchronized Reserve shortfall amount will be the difference between the lesser of the assigned plus self-scheduled amount or the PJM-calculated expected response and the actual response provided. The PJM-calculated expected response is based on the energy dispatch signals and instructions of the Office of the Interconnection. The Tier 2 Synchronized Reserve shortfall amount is for all Real-time Settlement Intervals the generation resource or Demand Resource was assigned and/or self-scheduled Tier 2 Synchronized Reserve on the Operating Day during which the event occurred. The determination of the amount of Synchronized Reserve credited to a generation resource or Demand Resource shall be on an individual resource basis, not on an aggregate basis.

The resource shall refund payments received for Tier 2 Synchronized Reserve it failed to provide. For purposes of determining the amount of the payments to be refunded by a Market Participant, the Office of the Interconnection shall calculate the shortfall of Tier 2 Synchronized Reserve on an individual resource basis unless the Market Participant had multiple Demand Resources that were assigned or self-scheduled to provide Tier 2 Synchronized Reserve, in which case the shortfall will be determined on an aggregate basis. For performance determined on an aggregate basis, the response of any Demand Resource that provided more Tier 2 Synchronized Reserve than it was assigned or self-scheduled to provide will be used to offset the performance of other Demand Resources that provided less Tier 2 Synchronized Reserve than they were assigned or self-scheduled to provide during a Synchronized Reserve Event, as

calculated in the PJM Manuals. The determination of a Market Participant's aggregate response shall not be taken into consideration in the determination of the amount of Tier 2 Synchronized Reserve credited to each individual Demand Resource.

The amount refunded shall be determined by multiplying the Synchronized Reserve Market Clearing Price by the amount of the shortfall of Tier 2 Synchronized Reserve, measured in megawatts, for all intervals the resource was assigned or self-scheduled to provide Tier 2 Synchronized Reserve for a period of time immediately preceding the Synchronized Reserve Event equal to the lesser of the average number of days between Synchronized Reserve Events, or the number of days since the resource last failed to provide the amount of Tier 2 Synchronized Reserve it was assigned or self-scheduled to provide in response to a Synchronized Reserve Event. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following January 1. The refunded charges shall be allocated as credits to Market Participants based on its pro rata share of the Synchronized Reserve Obligation megawatts less any Tier 1 Synchronized Reserve applied to its Synchronized Reserve Obligation in the hour(s) of the Synchronized Reserve Event for the Reserve Sub-zone or Reserve Zone, except that Market Participants that incur a refund obligation and also have an applicable Synchronized Reserve Obligation during the hour(s) of the Synchronized Reserve Event shall not be included in the allocation of such refund credits. If the event spans multiple hours, the refund credits will be prorated hourly based on the duration of the event within each clock hour.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or 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 or increased by the amount the megawatt output of the generation resource ~~falls below~~ differs from 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 but will be capped. If the generation resource has an assignment and the PJM-calculated expected response is greater than the assigned, then the megawatt output will be capped at the difference of the PJM-calculated expected response and the assigned. If the generation resource has no assignment, then the megawatt output will be capped at the PJM-calculated expected response. The PJM-calculated expected response is based on the energy dispatch signals and instructions of the Office of the Interconnection. 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 Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant with an hourly Non-Synchronized Reserve Obligation shall be charged the pro rata share of the sum of the quantity of Non-Synchronized Reserves provided in each Real-time Settlement Interval times the clearing price for all Real-time Settlement Intervals in the hour associated with that obligation.

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

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval of the Operating Day. The Non-Synchronized Reserve Market Clearing Price shall be calculated as the 5-minute clearing price. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve Requirement or Extended Primary Reserve Requirement. When

the Primary Reserve Requirement or Extended Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met in the pricing run at a price less than or equal to the applicable Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the 5-minute clearing price shall be the Reserve Penalty Factor for the Primary Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

The Reserve Penalty Factor for the Synchronized Reserve Requirement shall be \$850/MWh.

The Reserve Penalty Factor for the Extended Primary Reserve Requirement shall be \$300/MWh.

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

(d) For each Real-time Settlement Interval and for determining the 5-minute Non-Synchronized Reserve clearing price, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves will be determined in accordance with the following equation:

$$(A \times B) - C$$

Where:

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;

B = The Locational Marginal Price at the generation bus for the generation resource; and

C = The applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a resource 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 Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Non-Synchronized Reserve and shall be in accordance with the following equation:

$$(A \times B) - C$$

Where:

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;

B = The Locational Marginal Price at the generation bus for the generation resource; and

C = The applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

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

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

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

3.2.3A.01 Day-ahead Scheduling Reserves.

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

bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

(b) A Day-ahead Scheduling Reserves Resource that receives a Day-ahead Scheduling Reserves schedule pursuant to subsection (a) of this section shall be paid the hourly Day-ahead Scheduling Reserves Market clearing price, as determined in the day-ahead pricing run set forth in Operating Agreement, Schedule 1, section 2.6, for the cleared megawatt quantity of Day-ahead Scheduling Reserves 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 hourly credits paid to Day-ahead Scheduling Reserves Resources satisfying the Base Day-ahead Scheduling Reserves Requirement (“Base Day-ahead Scheduling Reserves credits”) shall equal the ratio of the Base Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement, multiplied by the total credits paid to Day-ahead Scheduling Reserves Resources, and are allocated as Base Day-ahead Scheduling Reserves charges per paragraph (i) below. The hourly credits paid to Day-ahead Scheduling Reserve Resources satisfying the Additional Day-ahead Scheduling Reserve Requirement (“Additional Day-ahead Scheduling Reserves credits”) shall equal the ratio of the Additional Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement, multiplied by the total credits paid to Day-ahead Scheduling Reserves Resources and are allocated as Additional Day-ahead Scheduling Reserves charges per paragraph (ii) below.

- (i) A Market Participant’s Base Day-ahead Scheduling Reserves charge is equal to the ratio of the Market Participant’s hourly obligation to the total hourly obligation of all Market Participants in the PJM Region, multiplied by the Base Day-ahead Scheduling Reserves credits. The hourly obligation for each Market Participant is a megawatt representation of the portion of the Base Day-ahead Scheduling Reserves credits that the Market Participant is responsible for paying to PJM. The hourly obligation is equal to the Market Participant’s load ratio share of the total megawatt volume of Base Day-ahead Scheduling Reserves resources (described below), based on the Market Participant’s total hourly load (net of operating Behind The Meter Generation, but not to be less than zero) to the total hourly load of all Market Participants in the PJM Region. The total megawatt volume of Base Day-ahead Scheduling Reserves resources equals the ratio of the Base Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement multiplied by the total volume of Day-ahead Scheduling Reserves megawatts paid pursuant to paragraph (c) of this section. A Market Participant’s hourly Day-ahead Scheduling Reserves obligation can be further adjusted by any Day-ahead Scheduling Reserve bilateral transactions.
- (ii) Additional Day-ahead Scheduling Reserves credits shall be charged hourly to Market Participants that are net purchasers in the Day-ahead Energy Market based on its positive demand difference ratio share. The positive demand difference for each Market Participant is the difference between its real-time load (net of operating Behind The Meter Generation, but not to be less than zero) and cleared Demand Bids in the Day-ahead Energy Market, net of cleared Increment Offers and cleared Decrement Bids in the Day-ahead Energy Market, when such value is positive. Net purchasers in the Day-ahead Energy Market are those Market

Participants that have cleared Demand Bids plus cleared Decrement Bids in excess of its amount of cleared Increment Offers in the Day-ahead Energy Market. If there are no Market Participants with a positive demand difference, the Additional Day-ahead Scheduling Reserves credits are allocated according to paragraph (i) above.

(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 real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than \$0.00. This equation is represented as $(A*B) - C$.

(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 for each Real-time Settlement Interval, limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the

Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(e) At the end of each Operating Day, where the active energy output 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 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 in an amount equal to $\{(AG - LMPDMW) \times (UB - URTLMP)\}$ where:

AG equals the actual 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 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 lesser of the Final Offer or Committed Offer;

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

where $UB - URTLMP$ shall not be negative.

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

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a

mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market Participant 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 Synchronized Reserve Market Clearing Price for each Real-time Settlement Interval a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generating unit's bus, (C) the generating unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generating resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generating unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of the Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

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

whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

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

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

3.2.3C Synchronous Condensing for Post-Contingency Operation.

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

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve.

At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Synchronized Reserve Market Clearing Price for each applicable interval a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's applicable interval cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the applicable interval 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 for the Synchronized Reserve Requirement and Primary Reserve Requirement, provided that the Emergency energy is needed to meet demand in the PJM Region.
- (b) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each applicable interval of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.
- (c) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each applicable interval of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.
- (d) The net costs or net revenues associated with sales or purchases of energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each applicable interval of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

- (a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Participant in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Participant's internal accounting.
- (b) If deliveries to a Market Participant that has PJM Interchange meters in accordance with 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 Participant, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market

Participant and the unmetered Market Participant specified by them to the Office of the Interconnection.

ATTACHMENT B
REVISIONS TO THE TARIFF AND
OPERATING AGREEMENT
(CLEAN)

1.11 Real-time Dispatch.

The Office of the Interconnection shall determine the least cost security constrained economic dispatch and send dispatch targets for each resource to Market Participants. The least cost security constrained economic dispatch is the least costly means of serving load and meeting reserve requirements at different locations in the PJM Region based on forecasted operating conditions on the power grid (including transmission constraints on external coordinated flowgates to the extent provided by Tariff, Attachment K-Appendix, section 1.7.6) as described in the PJM Manuals and on the offers for energy and ancillary services at which Market Sellers have entered as described by Tariff, Attachment K-Appendix, section 1.10 and Tariff, Attachment K-Appendix, section 2.4 and on offers by Economic Load Response Participants to reduce demand that qualify to set Locational Marginal Prices in the PJM Interchange Energy Market.

(a) To determine actual operating conditions on the power grid in the PJM Region (including transmission constraints on external coordinated flowgates to the extent provided by Tariff, Attachment K-Appendix, section 1.7.6), the Office of the Interconnection shall 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 as an input into the real-time security constrained economic dispatch. The computer model employed for this purpose, referred to as the State Estimator program, is a standard industry tool and is described in section 1.11A below. The State Estimator solution used by the real-time security constrained economic dispatch will be used to obtain information regarding the output of generation supplying energy to the PJM Region, loads at buses in the PJM Region, transmission losses, and power flows on binding transmission constraints.

(b) The Office of the Interconnection shall execute real-time security constrained economic dispatch for each five (5) minute target time, unless the Office of the Interconnection is unable to generate real-time security constrained economic dispatch solutions due to operational or technical issues, including but not limited to those described in the PJM Manuals. Each execution of the real-time security constrained economic dispatch shall result in several solutions, taking into consideration different operational scenarios.

(c) The Office of the Interconnection shall approve the applicable real-time security constrained economic dispatch solution for each five (5) minute target time, unless the Office of the Interconnection is unable to approve a real-time security constrained economic dispatch solution for the applicable target time due to a failure of the real-time security constrained economic dispatch program or other operational reasons. In such situations, either the most recently approved real-time security constrained economic dispatch solution shall persist, or the Office of the Interconnection shall manually dispatch the system.

1.11A 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 performing the security constrained economic dispatch of the system, 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. The 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 buses for which real-time information is unavailable. The Office of the Interconnection shall obtain the latest State Estimator solution each time a new security constrained economic dispatch is executed, 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 transmission facilities as defined in the PJM Manuals.

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 or self-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 or self-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.

As part of the real-time security constrained economic dispatch calculation, the Office of the Interconnection shall use submitted ramp rates to calculate the next dispatch point.

As part of the calculation, the Office of the Interconnection shall estimate the initial state of each generation resource based on its previous dispatch signal and the most recent State Estimator output. In the event the Office of the Interconnection is unable to approve a real-time security constrained economic dispatch solution for a period of time, due to a failure of the real-time

security constrained economic dispatch program or other operational reasons, the most recent State Estimator shall be used as the initial state. This evaluation methodology is calculated for all online dispatchable resources for each market solution in accordance with the PJM Manuals.

(a) The Office of the Interconnection shall implement the dispatch of energy from pool-scheduled resources with limited energy by direct request, by following the Day-ahead Market clearing, or by following the direct request of the Market Seller, subject to the Office of the Interconnection's determination of actions necessary to maintain reliability.

(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 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 upon receipt.

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 and Reserve Sub-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 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) Synchronized Reserve Events will be initiated by the Office of the Interconnection by approving the latest solved intelligent reserve deployment (IRD) case in the real-time security constrained economic dispatch application. When initiating a Synchronized Reserve Event, the Office of the Interconnection shall dispatch generation resources and direct the deployment of Demand Resources for Synchronized Reserve by transmitting Synchronized Reserve instructions to generation resources and Demand Resources through approval of the latest available IRD case solution in the real-time security constrained economic dispatch application, in accordance with the PJM Manuals. Market Sellers shall comply with Synchronized Reserve dispatch instructions transmitted by the Office of the Interconnection. 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. In the event the IRD case is not available (as described in Tariff, Attachment K-Appendix, Sections 1.11(b) and (c)), manual Synchronized Reserve deployment will be utilized, in accordance with PJM Manuals.

1.11.4B Non-Synchronized Reserve.

(a) A Market Buyer may satisfy its Non-Synchronized Reserve Obligation from its own generation 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. PJMSettlement shall be the Counterparty to the purchases and sales of Non-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-supply of generation resources by a Market Buyer to satisfy its Non-Synchronized Reserve Obligation.

(b) The Office of the Interconnection shall obtain Non-Synchronized Reserve from the least-cost alternatives available from either pool-scheduled generation resources, as needed to ensure the Primary Reserve requirement of each Reserve Zone and Reserve Sub-zone of the PJM Region not otherwise satisfied by the Market Buyers. Resources eligible to sell Non-Synchronized Reserve shall be selected to provide Non-Synchronized Reserve on the basis of each generation 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 not providing energy because they are providing Non-Synchronized Reserve shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(c) The Office of the Interconnection shall dispatch generation resources for Non-Synchronized Reserve by sending Non-Synchronized Reserve instructions to generation 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.

3.2 Market Settlements.

If a dollar-per-MW-hour value is applied in a calculation under this section 3.2 where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW hour value is divided by the number of Real-time Settlement Intervals in the hour.

3.2.1 Spot Market Energy.

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

(b) Each Market Participant shall be charged for all of its Market Participant Energy Withdrawals scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price to be served in the PJM Interchange Energy Market.

(c) Each Market Participant shall be paid for all of its Market Participant Energy Injections scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price to be delivered to the PJM Interchange Energy Market.

(d) For each Day-ahead Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its Market Participant Energy Withdrawals scheduled times the Day-ahead System Energy Price and the sum of its Market Participant Energy Injections scheduled times the Day-ahead System Energy Price.

(e) For each Real-time Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its real-time Market Participant Energy Withdrawals less its scheduled Market Participant Energy Withdrawals times the Real-time System Energy Price and the sum of its real-time Market Participant Energy Injections less scheduled Market Participant Energy Injections times the Real-time System Energy Price. The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with section 3.1A of this Schedule shall be used in determining the real-time Market Participant Energy Withdrawals and Market Participant Energy Injections used to calculate Spot Market Energy charges under this subsection (e).

(f) For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the megawatts of real-time energy injections to be delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region

3.2.2 Regulation.

(a) Each Market Participant that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). A Market Participant with an hourly Regulation Obligation shall be charged the pro rata share of the sum of the Regulation market performance clearing price credits and Regulation market capability clearing price credits for the Real-time Settlement Intervals in an hour.

Regulation Charge = Hourly Regulation Obligation Share * (sum of the Real-time Settlement Interval Regulation credits in an hour)

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

(c) The total Regulation market-clearing price in each Regulation Zone shall be determined in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval. The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the

generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

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

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

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

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

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

(e) In determining the credit under subsection (b) to a Market Participant selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for (1) each Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Regulation, and (2) the last three Real-time Settlement Intervals of the preceding shoulder hour and the first three Real-time Settlement Intervals of the following shoulder hour in accordance with the PJM Manuals and below.

The unit-specific opportunity cost incurred during the Real-time Settlement Interval 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 each of the preceding three Real-time Settlement Intervals of the 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 Real-time Settlement Interval in order to provide Regulation and the resource's expected output in each of the preceding three Real-time Settlement Intervals of the shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in each of the preceding three Real-time Settlement Intervals of the 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 Real-time Settlement Interval) in the PJM Interchange Energy Market, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during each of the following three Real-time Settlement Intervals of the 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 Real-time Settlement Interval in order to provide Regulation and the resource's expected output in each of the following three Real-time Settlement Intervals of the shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in each of the following three Real-time Settlement Intervals of the 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 all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Market Participant in a Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

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

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

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

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

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

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

(j) The Office of the Interconnection shall calculate a unit-specific benefits factor for each of the dynamic Regulation signal and traditional Regulation signal in accordance with the PJM Manuals. Each resource shall be assigned a unit-specific benefits factor based on their

order in the merit order stack for the applicable Regulation signal. The unit-specific benefits factor is the point on the benefits factor curve that aligns with the last megawatt, adjusted by historical performance, that resource will add to the dynamic resource stack. Resources following the dynamic Regulation signal which have a unit-specific benefits factor less than 0.1 will not be considered for the purposes of committing resources. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

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

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

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

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

where δ is delay.

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

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

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

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

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

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

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

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

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

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

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

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

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region multiplied by the historic accuracy score of the resource and multiplied by the unit-specific benefits factor for which the capability cost-based offer plus the performance cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The three-pivotal supplier test will apply on a Regulation supplier basis (i.e. not a resource by resource basis) and only the Regulation suppliers that fail the three-pivotal supplier test will have their Regulation offers capped. A Regulation supplier for the purposes of this section includes corporate affiliates. Regulation from resources controlled by a Regulation supplier or its affiliates, whether by contract with unaffiliated third parties or otherwise, will be included as Regulation of that Regulation supplier. Regulation provided by resources owned by a Regulation supplier but controlled by an unaffiliated third party, whether by contract or otherwise, will be included as Regulation of that third party.

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

a third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the applicable offer for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that 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. PJMSettlement shall be the Counterparty to the purchases and sales of Operating Reserve in the PJM Interchange Energy Market.

(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 Costs and No-load Costs and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. PJM shall also (i) determine whether any resources were scheduled in the Day-ahead Energy Market to provide Black Start service, Reactive Services or transfer interface control during the Operating Day because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day in order to minimize the total cost of Operating Reserves associated with the provision of such services and reflect the most accurate possible expectation of real-time operating conditions in the day-ahead model, which resources would not have otherwise been committed in the day-ahead security-constrained dispatch and (ii) report on the day following the Operating Day the megawatt quantities scheduled in the Day-ahead Energy Market for the above-enumerated purposes for the entire RTO.

Except as provided in Section 3.2.3(n), if the total offered price for Start-up Costs (shutdown costs for Demand Resources) and No-load Costs and energy summed over all Day-ahead Settlement Intervals exceeds the total value summed over all Day-ahead Settlement Intervals, the difference shall be credited to the Market Seller as a day-ahead Operating Reserve credit.

However, for the Day-ahead Settlement Intervals in which the resource is scheduled to provide energy in the Operating Day and the resource actually provides energy in at least one Real-time Settlement Interval in an hour that corresponds to such scheduled Day-ahead Settlement Intervals, a resource's day-ahead Operating Reserve credit shall be reduced by the greater of zero or the difference of the resource's Day-ahead Operating Reserve Target and the Balancing Operating Reserve Target, as determined below.

A resource's Day-ahead Operating Reserve Target shall be determined in accordance with the following equation:

$$(A + B) - C$$

Where:

A = Start-up Costs

B = the sum of day-ahead No-load Costs and energy over the applicable Real-time Settlement Intervals that correspond with Day-ahead Settlement Intervals in which the resource is scheduled. The day-ahead No-load Costs and energy are divided by twelve to determine the cost for each Real-time Settlement Interval.

C = the sum of the day-ahead revenues calculated for each Real-time Settlement Interval that corresponds with a Day-ahead Settlement Interval in which the resource is scheduled, where the day-ahead revenue for each such Real-time Settlement Interval equals the product of the megawatt amount of energy scheduled in the Day-ahead Energy Market and the Day-ahead Price at the applicable pricing point for the resource divided by twelve.

A resource's Balancing Operating Reserve Target shall be determined in accordance with the following equation:

$$D - (E + F)$$

Where:

D = the sum of Start-up Costs and No-load Costs and the incremental cost of energy summed over all Real-time Settlement Intervals that correspond to the Day-ahead Settlement Intervals in which the resource was scheduled;

E = [(the megawatt amount of energy provided in the Real-time Energy Market minus the megawatt amount of energy scheduled in the Day-ahead Energy Market) multiplied by the Real-time Price at the applicable pricing point for the resource] plus the sum of the day-ahead revenues as determined in part C of the above formula for determining the Day-ahead Operating Reserve Target, summed over the applicable Real-time Settlement Intervals; and

F = the sum of all revenues earned for providing Day-ahead Scheduling Reserves, Synchronized Reserves, Non-Synchronized Reserves, and Reactive Services over the applicable Real-time Settlement Intervals.

The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this section 3.2.3(b) to real-time deviations or real-time load share plus exports, pursuant to Tariff, Attachment K-Appendix, section 3.2.3(p), 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.

(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), accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day and accepted Up-to Congestion Transactions in the Day-ahead Energy Market in megawatt-hours for the Operating Day at the sink of the transaction; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside such area pursuant to Section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load (net of operating Behind The Meter Generation) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following Segments: 1) the greater of their day-ahead schedules and minimum run time specified at the time of commitment (minimum

down time specified at the time of commitment for Demand Resources); and 2) any block of Real-time Settlement Intervals the resource operates at PJM's direction in excess of the greater of its day-ahead schedule and minimum run time specified at the time of commitment (minimum down time specified at the time of commitment for 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 specified at the time of commitment (minimum down time specified at the time of commitment for Demand Resources) and Segment 2 will include the remainder of the contiguous Real-time Settlement Intervals when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

A Generation Capacity Resource that operates outside of its unit-specific parameters will not receive Operating Reserve Credits nor be made whole for such operation when not dispatched by the Office of the Interconnection, unless the Market Seller of the Generation Capacity Resource can justify to the Office of the Interconnection that operation outside of such unit-specific parameters was the result of an actual constraint. Such Market Seller shall provide to the Market Monitoring Unit and the Office of the Interconnection its request to receive Operating Reserve Credits and/or to be made whole for such operation, along with documentation explaining in detail the reasons for operating its resource outside of its unit-specific parameters, within thirty calendar days following the issuance of billing statement for the Operating Day. The Market Seller shall also respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection. The Market Monitoring Unit shall evaluate such request for compensation and provide its determination of whether there was an exercise of market power to the Office of the Interconnection by no later than twenty-five calendar days after receiving the Market Seller's request for compensation. The Office of the Interconnection shall make its determination whether the Market Seller justified that it is entitled to receive Operating Reserve Credits and/or be made whole for such operation of its resource for the day(s) in question, by no later than thirty calendar days after receiving the Market Seller's request for compensation.

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 Tariff, Attachment K-Appendix, section 3.2.3(f) and the parallel provision of Operating Agreement, Schedule 1, section 3.2.3(f); or 2) the resource submits a request for a risk premium to the Market Monitoring Unit under the procedures specified in Tariff, Attachment M – Appendix, section II.B. A nuclear generation resource (i) must submit a risk premium consistent with its agreement under such process, or, (ii) if it has not agreed with the Market Monitoring Unit on an appropriate risk premium, may submit its own determination of an appropriate risk premium to the Office of the Interconnection, subject to acceptance by the Office of the Interconnection, with or without prior approval from the Commission.

Credits received pursuant to this section shall be equal to the positive difference between a resource's Total Operating Reserve Offer, and the total value of the resource's energy in the

Day-ahead Energy Market plus any credit or change for quantity deviations, at PJM dispatch direction (excluding quantity deviations caused by an increase in the Market Seller's Real-time Offer), from the Day-ahead Energy Market during the Operating Day at the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for Segment 2 shall exclude start up (shutdown costs for Demand Resources) costs for generation resources.

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

Synchronized Reserve, Non-Synchronized Reserve, and Real-time Settlement Interval share of the 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 Real-time Settlement Interval(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 Real-time Settlement Interval the unit operates in condensing and generation mode.

(f) A Market Seller of a unit not defined in subsection (f-1), (f-2), or (f-4) hereof (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than \$0.00. This equation is represented as $(A*B) - C$.

(f-1) With the exception of Market Sellers of Flexible Resources that submit a Real-time Offer greater than their resource's Committed Offer in the Day-ahead Energy Market, a Market Seller of a Flexible Resource shall be compensated for lost opportunity cost, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if either of the following conditions occur:

- (i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described in section 3.2.3 (f).
- (ii) If the unit is scheduled to produce energy in the Day-ahead Energy Market for a Day-ahead Settlement Interval, but the unit is not called on by the Office of the Interconnection and does not operate in the corresponding Real-time Settlement Interval(s), then the Market Seller shall be credited in an amount equal to the higher of:
 - 1) the product of (A) the amount of megawatts committed in the Day-ahead Energy Market for the generating unit, and (B) the Real-time Price at the generation bus for the generating unit, minus the sum of (C) the Total Lost Opportunity Cost Offer plus No-load Costs, plus (D) the Start-up Cost, divided by the Real-time Settlement Intervals committed for each set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market. This equation is represented as $(A*B) - (C+D)$. The startup cost, (D), shall be excluded from this calculation if the unit operates in real time following the Office of the Interconnection's direction during any portion of the set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market, or
 - 2) the Real-time Price at the unit's bus minus the Day-ahead Price at the unit's bus, multiplied by the number of megawatts committed in the Day-ahead Energy Market for the generating unit.

Market Sellers of Flexible Resources that submit a Real-time Offer greater than their resource's Committed Offer in the Day-ahead Energy Market shall not be eligible to receive compensation for lost opportunity costs under any applicable provisions of Schedule 1 of this Agreement.

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

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output

due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-4) A Market Seller of a wind generating unit that is pool-scheduled or self-scheduled, has SCADA capability to transmit and receive instructions from the Office of the Interconnection, has provided data and established processes to follow PJM basepoints pursuant to the requirements for wind generating units as further detailed in this Agreement, the Tariff and the PJM Manuals, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the , real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than \$0.00. This equation is represented as $(A*B) - C$.

(f-5) (i) A Market Seller of a pool-scheduled resource or a dispatchable self-scheduled resource shall receive Dispatch Differential Lost Opportunity Cost credits as calculated under subsection (iv) below if the resource is dispatched to provide energy in the Real-time Energy Market, provided such resource is not committed to provide real-time ancillary services (Regulation, reserves, reactive service) or instructed to reduce or suspend output due to a transmission constraint or other reliability issue pursuant to Tariff, Attachment K-Appendix, section 3.2.3(f-1) through Tariff, Attachment K-Appendix, section (f-4).

(ii) PJM will calculate the revenue above cost for the pricing run for each Real-time Settlement Interval in accordance with the following equation:

$$(A \times B) - C$$

Where:

A = the resource's expected output level based on its resource parameters at the Real-time Price at the applicable pricing point;

B = the Real-time Price at the applicable pricing point; and

C = the sum of the resource's Real-time Energy Market offer integrated under the Final Offer for the resource's expected output level based on its resource parameters at the Real-time Price at the applicable pricing point.

(iii) PJM will calculate the revenue above cost for the dispatch run for each Real-time Settlement Interval in accordance with the following equation:

$$(\text{greater of A and B}) - (\text{lesser of C and D})$$

Where:

A = the product of the amount of megawatts of energy dispatched in the Real-time Energy Market dispatch run for the resource in that Real-time Settlement Interval and the Real-time Price at the applicable pricing point;

B = the product of the amount of megawatts of energy the resource actually provided in that Real-time Settlement Interval and the Real-time Price at the applicable pricing point;

C = the resource's Real-time Energy Market offer integrated under the Final Offer for the amount of megawatts dispatched in the Real-time Energy Market dispatch run;

D = the resource's Real-time Energy Market offer integrated under the Final Offer for the amount of megawatts the resource actually provided in that Real-time Settlement Interval.

(iv) The Dispatch Differential Lost Opportunity Cost credit shall equal the greater of (A) the difference between the revenue above cost based on the pricing run determined in subsection (f-5)(ii) and the revenue above cost based on the dispatch run determined in subsection (f-5)(iii) or (B) zero.

(v) For each hour in an Operating Day, the total cost of the Dispatch Differential Lost Opportunity Cost credits shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load ((a) net of operating Behind The Meter Generation, but not to be less than zero; and (b) excluding Direct Charging Energy) in the PJM Region, served under Network Transmission Service, in megawatt-hours; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Tariff, Attachment K-Appendix, section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(g) The sum of the foregoing credits in Tariff, Attachment K-Appendix, section 3.2.3(f-1) through Tariff, Attachment K-Appendix, section 3.2.3(f-4), 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 shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, shall be allocated and charged to each Market Participant based on their daily total of hourly deviations determined in accordance with the following equation:

$$\sum_h (A + B + C)$$

Where:

h = the hours in the applicable Operating Day;

A = For each Real-time Settlement Interval in an hour, the sum of the absolute value of the withdrawal deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy withdrawals (net of operating Behind The Meter Generation) in the Real-Time Energy Market, except as noted in subsection (h)(ii) below and in the PJM Manuals divided by the number of Real-time Settlement Intervals for that hour. The summation of each Real-time Settlement Interval's withdrawal deviation in an hour will be the Market Participant's total hourly withdrawal deviations. Market Participant bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to section 1.12 of this Schedule are not included in the determination of withdrawal deviations;

B = For each Real-time Settlement Interval in an hour, the sum of the absolute value of generation deviations (in MW and not including deviations in Behind The Meter Generation) as determined in subsection (o) divided by the number of Real-Time Settlement Intervals for that hour;

C = For each Real-time Settlement Interval in an hour, the sum of the absolute value of the injection deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy injections in the Real-Time Energy Market divided by the number of Real-time Settlement Intervals for that hour. The summation of the injection deviations for each Real-time Settlement Interval in an hour will be the Market Participant's total hourly injection deviations. The determination of injection deviations does not include generation resources.

The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with section 3.1A of this Schedule shall be used in determining the real-time withdrawal deviations, generation deviations and injection deviations used to calculate Operating Reserve under this subsection (e).

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

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

Deviations that occur within a single Zone shall be associated with the Eastern or Western Region, as defined in Section 3.2.3(q) of this Schedule, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with Section 3.2.3(q). Deviations at a hub shall be associated with the Eastern or Western Region if all the buses that define the hub are located in the region. Deviations at an Interface Pricing Point shall be associated with whichever region, the Eastern or Western Region, with which the majority of the buses that define that Interface Pricing Point are most closely electrically associated. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by buses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed for each Real-time Settlement Interval in accordance with the following provisions:

- (i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.
- (ii) Demand deviations will be assessed by comparing all day-ahead demand transactions, which include the components referenced in section 3.2.3(d) regarding the cost of Operating Reserves in the Day-ahead Energy Market, at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.
- (iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.
- (iv) Bilateral transactions inside the PJM Region, as defined in Operating Agreement, Schedule 1, section 1.7.10, will not be included in the determination of Supply or Demand deviations.

(i) At the end of each Operating Day, Market Sellers shall be credited 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 Dynamic Transfers 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 and greater than the Market Seller’s lowest

available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. 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 Real-time Settlement Intervals that the offer is economic divided by the megawatt hours of energy provided during the Real-time Settlement Intervals that the offer is economic. The Real-time Settlement Intervals that the offer is economic shall be: (i) the Real-time Settlement Intervals that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the Real-time Settlement Intervals in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any Real-time Settlement Intervals required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price for a market-based offer is greater than \$1,000/MWh and greater than the Market Seller's lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than \$1,000/MWh, the Market Seller shall receive credit for 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 below and in the PJM Manuals.

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

- (i) real-time economic minimum \leq 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.
- (ii) real-time economic maximum \geq 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

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

$$Ramp_Request_t = (Dispatchtarget_{t-1} - AOutput_{t-1}) / (LAtime_{t-1})$$

$$RL_Desired_t = AOutput_{t-1} + (Ramp_Request_t * Case_Eff_time_{t-1})$$

where:

1. Dispatchtarget = Dispatch Signal for the previous approved Dispatch case
2. AOutput = Unit's achievable target MW at case solution time as defined in the PJM Manuals
3. LAtime = Dispatch look ahead time
4. Case_Eff_time = Time between signal changes
5. RL_Desired = Ramp-limited desired MW

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

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and dispatch signal, or if its %

off dispatch is ≤ 10 , or its Real-time Settlement Interval MWh is within 5% of the Real-time Settlement Interval ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined for each Real-time Settlement Interval in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – Day-Ahead MWh.
- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – dispatch LMP Desired MW.
- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – Ramp-Limited Desired MW.
- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and dispatch LMP Desired MWh for the Real-time Settlement Interval is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: Real time Settlement Interval MWh – dispatch LMP Desired MWh.
- If a resource is not following dispatch and its % Off Dispatch is $\leq 20\%$, balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh – Ramp-Limited Desired MW. If deviation value is within 5% of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.
- If a resource is not following dispatch and its % off Dispatch is $> 20\%$, balancing Operating Reserve deviations shall be assessed according to the following formula: Real time Settlement Interval MWh – dispatch LMP Desired MWh.
- If a resource is not following dispatch, and the resource has tripped, for the Real-time Settlement Interval the resource tripped and the Real-time Settlement Intervals it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: Real time Settlement Interval MWh – Day-Ahead MWh.
- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh - Day-Ahead MWh.

If a resource has a sum of the absolute value of generator deviations for an hour that is less than 5 MWh, then the resource shall not be assessed balancing Operating Reserve deviations for that hour.

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

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

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

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

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

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

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

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

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

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

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

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

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total

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

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

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

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

(r) Market Sellers that incur incremental operating costs for a generation resource that are either greater than \$1,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Schedule 2 of the Operating Agreement and PJM Manual 15, but are not verified at the time of dispatch of the resource under section 6.4.3 of this Schedule, or greater than \$2,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Schedule 2 of the Operating Agreement, and PJM Manual 15, will be eligible to receive credit for Operating Reserves upon review of the Market Monitoring Unit and the Office of the Interconnection, and approval of the Office of the Interconnection. Market Sellers must submit to the Office of the Interconnection and the Market Monitoring Unit all relevant documentation demonstrating the calculation of costs greater than \$2,000/MWh, and costs greater than \$1,000/MWh which were not verified at the time of dispatch of the resource under section 6.4.3 of this Schedule. The Office of the Interconnection must approve any Operating Reserve credits paid to a Market Seller under this subsection (r).

3.2.3A Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter

Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour (“Synchronized Reserve Obligation”), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b).

Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant with an hourly Synchronized Reserve Obligation shall be charged the pro rata share of the sum of the quantity of Synchronized Reserves provided in each Real-time Settlement Interval times the clearing price for all Real-time Settlement Intervals in the hour associated with that obligation.

(b) A resource 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, as described in 3.2.3A (c), with the exception of those Real-time Settlement Intervals in which the Non-Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone is not equal to zero. During such hours, Tier 1 Synchronized Reserve resources shall be compensated at the Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone for the lesser of the 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 in a Real-time Settlement Interval.

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 to a Synchronized Reserve Event in a Real-time Settlement Interval 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 in a Real-time Settlement Interval 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 an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval of the Operating Day. The hourly Synchronized Reserve Market Clearing Price shall be calculated as the 5-minute clearing price. Each 5-minute clearing price shall be calculated as the marginal cost of serving the next increment of demand for Synchronized Reserve in each Reserve Zone or Reserve Sub-zone, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve Requirement or Extended Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met in the pricing run, the 5-minute clearing price shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the sum of the Reserve Penalty Factors for the Synchronized Reserve Requirement and Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the 5-minute clearing price shall be the sum of the Reserve Penalty Factors for the Primary Reserve Requirement and the Synchronized Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

The Reserve Penalty Factor for the Synchronized Reserve Requirement shall be \$850/MWh.

The Reserve Penalty Factor for the Extended Synchronized Reserve Requirement shall be \$300/MWh.

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

(e) For each Real-time Settlement Interval and for determining the 5-minute Synchronized Reserve clearing price, the estimated unit-specific opportunity cost for a generation resource will be determined in accordance with the following equation:

$$(A \times B) + (C \times D)$$

Where

A = The Locational Marginal Price at the generation bus for the generation resource;

B = The megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer;

C = 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; and

D = The difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a resource 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 Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be in accordance with the following equation:

$$(A \times B) + (C \times D)$$

Where:

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;

B = The Locational Marginal Price at the generation bus of the generation resource;

C = 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; and

D = 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 Participant in excess of that Market Participant's Synchronized Reserve Obligation, the Tier 1 Synchronized Reserve that is not utilized to fulfill the Market Participant's obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

(h) Any amounts credited for Tier 2 Synchronized Reserve in a Real-time Settlement Interval in excess of the Synchronized Reserve Market Clearing Price in that Real-time Settlement Interval shall be allocated and charged to each Market Participant 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 a Real-time Settlement Interval than was estimated as needed at the time the Synchronized Reserve Market Clearing Price was calculated for that Real-time Settlement Interval 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) A generation resource or Demand Resource will be credited for the assigned and/or self-scheduled amount of Tier 2 Synchronized Reserve, less any applicable Tier 2 Synchronized Reserve shortfall, multiplied by the Synchronized Reserve Market Clearing Price for each Real-Time Settlement Interval, in which they were assigned and/or self-scheduled. In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled to provide Tier 2 Synchronized Reserve fails to provide the PJM calculated expected response of Tier 2 Synchronized Reserve in response to a Synchronized Reserve Event, the generation resource or Demand Resource will have a Tier 2 Synchronized Reserve shortfall. The Tier 2 Synchronized Reserve shortfall amount will be the difference between the lesser of the assigned plus self-scheduled amount or the PJM-calculated expected response and the actual response provided. The PJM-calculated expected response is based on the energy dispatch signals and instructions of the Office of the Interconnection. The Tier 2 Synchronized Reserve shortfall amount is for all Real-time Settlement Intervals the generation resource or Demand Resource was assigned and/or self-scheduled Tier 2 Synchronized Reserve on the Operating Day during which the event occurred. The determination of the amount of Synchronized Reserve credited to a generation resource or Demand Resource shall be on an individual resource basis, not on an aggregate basis.

The resource shall refund payments received for Tier 2 Synchronized Reserve it failed to provide. For purposes of determining the amount of the payments to be refunded by a Market Participant, the Office of the Interconnection shall calculate the shortfall of Tier 2 Synchronized Reserve on an individual resource basis unless the Market Participant had multiple Demand Resources that were assigned or self-scheduled to provide Tier 2 Synchronized Reserve, in which case the shortfall will be determined on an aggregate basis. For performance determined on an aggregate basis, the response of any Demand Resource that provided more Tier 2 Synchronized Reserve than it was assigned or self-scheduled to provide will be used to offset the performance of other Demand Resources that provided less Tier 2 Synchronized Reserve than they were assigned or self-scheduled to provide during a Synchronized Reserve Event, as calculated in the PJM Manuals. The determination of a Market Participant's aggregate response

shall not be taken into consideration in the determination of the amount of Tier 2 Synchronized Reserve credited to each individual Demand Resource.

The amount refunded shall be determined by multiplying the Synchronized Reserve Market Clearing Price by the amount of the shortfall of Tier 2 Synchronized Reserve, measured in megawatts, for all intervals the resource was assigned or self-scheduled to provide Tier 2 Synchronized Reserve for a period of time immediately preceding the Synchronized Reserve Event equal to the lesser of the average number of days between Synchronized Reserve Events, or the number of days since the resource last failed to provide the amount of Tier 2 Synchronized Reserve it was assigned or self-scheduled to provide in response to a Synchronized Reserve Event. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following January 1. The refunded charges shall be allocated as credits to Market Participants based on its pro rata share of the Synchronized Reserve Obligation megawatts less any Tier 1 Synchronized Reserve applied to its Synchronized Reserve Obligation in the hour(s) of the Synchronized Reserve Event for the Reserve Sub-zone or Reserve Zone, except that Market Participants that incur a refund obligation and also have an applicable Synchronized Reserve Obligation during the hour(s) of the Synchronized Reserve Event shall not be included in the allocation of such refund credits. If the event spans multiple hours, the refund credits will be prorated hourly based on the duration of the event within each clock hour.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or 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 or increased by the amount the megawatt output of the generation resource differs from 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 but will be capped. If the generation resource has an assignment and the PJM-calculated expected response is greater than the assigned, then the megawatt output will be capped at the difference of the PJM-calculated expected response and the assigned. If the generation resource has no assignment, then the megawatt output will be capped at the PJM-calculated expected response. The PJM-calculated expected response is based on the energy dispatch signals and instructions of the Office of the Interconnection. 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 Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant with an hourly Non-Synchronized Reserve Obligation shall be charged the pro rata share of the sum of the quantity of Non-Synchronized Reserves provided in each Real-time Settlement Interval times the clearing price for all Real-time Settlement Intervals in the hour associated with that obligation.

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

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval of the Operating Day. The Non-Synchronized Reserve Market Clearing Price shall be calculated as the 5-minute clearing price. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve Requirement or Extended Primary Reserve Requirement. When the Primary Reserve Requirement or Extended Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met in the pricing run at a price less than or equal to the

applicable Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the 5-minute clearing price shall be the Reserve Penalty Factor for the Primary Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

The Reserve Penalty Factor for the Synchronized Reserve Requirement shall be \$850/MWh.

The Reserve Penalty Factor for the Extended Primary Reserve Requirement shall be \$300/MWh.

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

(d) For each Real-time Settlement Interval and for determining the 5-minute Non-Synchronized Reserve clearing price, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves will be determined in accordance with the following equation:

$$(A \times B) - C$$

Where:

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;

B = The Locational Marginal Price at the generation bus for the generation resource; and

C = The applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a resource 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 Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Non-Synchronized Reserve and shall be in accordance with the following equation:

$$(A \times B) - C$$

Where:

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;

B = The Locational Marginal Price at the generation bus for the generation resource; and

C = The applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

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

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

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

3.2.3A.01 Day-ahead Scheduling Reserves.

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

bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

(b) A Day-ahead Scheduling Reserves Resource that receives a Day-ahead Scheduling Reserves schedule pursuant to subsection (a) of this section shall be paid the hourly Day-ahead Scheduling Reserves Market clearing price, as determined in the day-ahead pricing run set forth in Tariff, Attachment K-Appendix, section 2.6, for the cleared megawatt quantity of Day-ahead Scheduling Reserves 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 hourly credits paid to Day-ahead Scheduling Reserves Resources satisfying the Base Day-ahead Scheduling Reserves Requirement (“Base Day-ahead Scheduling Reserves credits”) shall equal the ratio of the Base Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement, multiplied by the total credits paid to Day-ahead Scheduling Reserves Resources, and are allocated as Base Day-ahead Scheduling Reserves charges per paragraph (i) below. The hourly credits paid to Day-ahead Scheduling Reserve Resources satisfying the Additional Day-ahead Scheduling Reserve Requirement (“Additional Day-ahead Scheduling Reserves credits”) shall equal the ratio of the Additional Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement, multiplied by the total credits paid to Day-ahead Scheduling Reserves Resources and are allocated as Additional Day-ahead Scheduling Reserves charges per paragraph (ii) below.

- (i) A Market Participant’s Base Day-ahead Scheduling Reserves charge is equal to the ratio of the Market Participant’s hourly obligation to the total hourly obligation of all Market Participants in the PJM Region, multiplied by the Base Day-ahead Scheduling Reserves credits. The hourly obligation for each Market Participant is a megawatt representation of the portion of the Base Day-ahead Scheduling Reserves credits that the Market Participant is responsible for paying to PJM. The hourly obligation is equal to the Market Participant’s load ratio share of the total megawatt volume of Base Day-ahead Scheduling Reserves resources (described below), based on the Market Participant’s total hourly load (net of operating Behind The Meter Generation, but not to be less than zero) to the total hourly load of all Market Participants in the PJM Region. The total megawatt volume of Base Day-ahead Scheduling Reserves resources equals the ratio of the Base Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement multiplied by the total volume of Day-ahead Scheduling Reserves megawatts paid pursuant to paragraph (c) of this section. A Market Participant’s hourly Day-ahead Scheduling Reserves obligation can be further adjusted by any Day-ahead Scheduling Reserve bilateral transactions.
- (ii) Additional Day-ahead Scheduling Reserves credits shall be charged hourly to Market Participants that are net purchasers in the Day-ahead Energy Market based on its positive demand difference ratio share. The positive demand difference for each Market Participant is the difference between its real-time load (net of operating Behind The Meter Generation, but not to be less than zero) and cleared Demand Bids in the Day-ahead Energy Market, net of cleared Increment Offers and cleared Decrement Bids in the Day-ahead Energy Market, when such value is positive. Net purchasers in the Day-ahead Energy Market are those Market

Participants that have cleared Demand Bids plus cleared Decrement Bids in excess of its amount of cleared Increment Offers in the Day-ahead Energy Market. If there are no Market Participants with a positive demand difference, the Additional Day-ahead Scheduling Reserves credits are allocated according to paragraph (i) above.

(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 real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than \$0.00. This equation is represented as $(A*B) - C$.

(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 for each Real-time Settlement Interval, limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the

Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(e) At the end of each Operating Day, where the active energy output 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 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 in an amount equal to $\{(AG - LMPDMW) \times (UB - URTLMP)\}$ where:

AG equals the actual 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 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 lesser of the Final Offer or Committed Offer;

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

where $UB - URTLMP$ shall not be negative.

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

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a

mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market Participant 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 Synchronized Reserve Market Clearing Price for each Real-time Settlement Interval a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generating unit's bus, (C) the generating unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generating resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generating unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of the Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

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

whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

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

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

3.2.3C Synchronous Condensing for Post-Contingency Operation.

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

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve.

At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Synchronized Reserve Market Clearing Price for each applicable interval a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's applicable interval cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the applicable interval 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 for the Synchronized Reserve Requirement and Primary Reserve Requirement, provided that the Emergency energy is needed to meet demand in the PJM Region.
- (b) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each applicable interval of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.
- (c) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each applicable interval of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.
- (d) The net costs or net revenues associated with sales or purchases of energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each applicable interval of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

- (a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Participant in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Participant's internal accounting.
- (b) If deliveries to a Market Participant that has PJM Interchange meters in accordance with 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 Participant, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market

Participant and the unmetered Market Participant specified by them to the Office of the Interconnection.

1.11 Real-time Dispatch.

The Office of the Interconnection shall determine the least cost security constrained economic dispatch and send dispatch targets for each resource to Market Participants. The least cost security constrained economic dispatch is the least costly means of serving load and meeting reserve requirements at different locations in the PJM Region based on forecasted operating conditions on the power grid (including transmission constraints on external coordinated flowgates to the extent provided by Operating Agreement, Schedule 1, section 1.7.6) as described in the PJM Manuals and on the offers for energy and ancillary services at which Market Sellers have entered as described by Operating Agreement, Schedule 1, section 1.10 and Operating Agreement, Schedule 1, section 2.4 and on offers by Economic Load Response Participants to reduce demand that qualify to set Locational Marginal Prices in the PJM Interchange Energy Market.

(a) To determine actual operating conditions on the power grid in the PJM Region (including transmission constraints on external coordinated flowgates to the extent provided by Operating Agreement, Schedule 1, section 1.7.6), the Office of the Interconnection shall 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 as an input into the real-time security constrained economic dispatch. The computer model employed for this purpose, referred to as the State Estimator program, is a standard industry tool and is described in section 1.11A below. The State Estimator solution used by the real-time security constrained economic dispatch will be used to obtain information regarding the output of generation supplying energy to the PJM Region, loads at buses in the PJM Region, transmission losses, and power flows on binding transmission constraints.

(b) The Office of the Interconnection shall execute real-time security constrained economic dispatch for each five (5) minute target time, unless the Office of the Interconnection is unable to generate real-time security constrained economic dispatch solutions due to operational or technical issues, including but not limited to those described in the PJM Manuals. Each execution of the real-time security constrained economic dispatch shall result in several solutions, taking into consideration different operational scenarios.

(c) The Office of the Interconnection shall approve the applicable real-time security constrained economic dispatch solution for each five (5) minute target time, unless the Office of the Interconnection is unable to approve a real-time security constrained economic dispatch solution for the applicable target time due to a failure of the real-time security constrained economic dispatch program or other operational reasons. In such situations, either the most recently approved real-time security constrained economic dispatch solution shall persist, or the Office of the Interconnection shall manually dispatch the system.

1.11A 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 performing the security constrained economic dispatch of the system, 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. The 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 buses for which real-time information is unavailable. The Office of the Interconnection shall obtain the latest State Estimator solution each time a new security constrained economic dispatch is executed, 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 transmission facilities as defined in the PJM Manuals.

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 or self-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 or self-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.

As part of the real-time security constrained economic dispatch calculation, the Office of the Interconnection shall use submitted ramp rates to calculate the next dispatch point.

As part of the calculation, the Office of the Interconnection shall estimate the initial state of each generation resource based on its previous dispatch signal and the most recent State Estimator output. In the event the Office of the Interconnection is unable to approve a real-time security constrained economic dispatch solution for a period of time, due to a failure of the real-time

security constrained economic dispatch program or other operational reasons, the most recent State Estimator shall be used as the initial state. This evaluation methodology is calculated for all online dispatchable resources for each market solution in accordance with the PJM Manuals.

(a) The Office of the Interconnection shall implement the dispatch of energy from pool-scheduled resources with limited energy by direct request, by following the Day-ahead Market clearing, or by following the direct request of the Market Seller, subject to the Office of the Interconnection's determination of actions necessary to maintain reliability.

(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 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 upon receipt.

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 and Reserve Sub-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 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) Synchronized Reserve Events will be initiated by the Office of the Interconnection by approving the latest solved intelligent reserve deployment (IRD) case in the real-time security constrained economic dispatch application. When initiating a Synchronized Reserve Event, the Office of the Interconnection shall dispatch generation resources and direct the deployment of Demand Resources for Synchronized Reserve by transmitting Synchronized Reserve instructions to generation resources and Demand Resources through approval of the latest available IRD case solution in the real-time security constrained economic dispatch application, in accordance with the PJM Manuals. Market Sellers shall comply with Synchronized Reserve dispatch instructions transmitted by the Office of the Interconnection. 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. In the event the IRD case is not available (as described in Tariff, Attachment K-Appendix, Sections 1.11(b) and (c)), manual Synchronized Reserve deployment will be utilized, in accordance with PJM Manuals.

1.11.4B Non-Synchronized Reserve.

(a) A Market Buyer may satisfy its Non-Synchronized Reserve Obligation from its own generation 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. PJMSettlement shall be the Counterparty to the purchases and sales of Non-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-supply of generation resources by a Market Buyer to satisfy its Non-Synchronized Reserve Obligation.

(b) The Office of the Interconnection shall obtain Non-Synchronized Reserve from the least-cost alternatives available from either pool-scheduled generation resources as needed to ensure the Primary Reserve requirement of each Reserve Zone and Reserve Sub-zone of the PJM Region not otherwise satisfied by the Market Buyers. Resources eligible to sell Non-Synchronized Reserve shall be selected to provide Non-Synchronized Reserve on the basis of each generation 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 not providing energy because they are providing Non-Synchronized Reserve shall be equal to the product of (A) the deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generation resource, minus (C) the applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(c) The Office of the Interconnection shall dispatch generation resources for Non-Synchronized Reserve by sending Non-Synchronized Reserve instructions to generation

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.

3.2 Market Settlements.

If a dollar-per-MW-hour value is applied in a calculation under this section 3.2 where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW hour value is divided by the number of Real-time Settlement Intervals in the hour.

3.2.1 Spot Market Energy.

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

(b) Each Market Participant shall be charged for all of its Market Participant Energy Withdrawals scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price to be served in the PJM Interchange Energy Market.

(c) Each Market Participant shall be paid for all of its Market Participant Energy Injections scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price to be delivered to the PJM Interchange Energy Market.

(d) For each Day-ahead Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its Market Participant Energy Withdrawals scheduled times the Day-ahead System Energy Price and the sum of its Market Participant Energy Injections scheduled times the Day-ahead System Energy Price.

(e) For each Real-time Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its real-time Market Participant Energy Withdrawals less its scheduled Market Participant Energy Withdrawals times the Real-time System Energy Price and the sum of its real-time Market Participant Energy Injections less scheduled Market Participant Energy Injections times the Real-time System Energy Price. The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with section 3.1A of this Schedule shall be used in determining the real-time Market Participant Energy Withdrawals and Market Participant Energy Injections used to calculate Spot Market Energy charges under this subsection (e).

(f) For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the megawatts of real-time energy injections to be delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region

3.2.2 Regulation.

(a) Each Market Participant that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). A Market Participant with an hourly Regulation Obligation shall be charged the pro rata share of the sum of the Regulation market performance clearing price credits and Regulation market capability clearing price credits for the Real-time Settlement Intervals in an hour.

Regulation Charge = Hourly Regulation Obligation Share * (sum of the Real-time Settlement Interval Regulation credits in an hour)

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

(c) The total Regulation market-clearing price in each Regulation Zone shall be determined in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval. The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the

generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

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

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

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

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

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

(e) In determining the credit under subsection (b) to a Market Participant selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for (1) each Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Regulation, and (2) the last three Real-time Settlement Intervals of the preceding shoulder hour and the first three Real-time Settlement Intervals of the following shoulder hour in accordance with the PJM Manuals and below.

The unit-specific opportunity cost incurred during the Real-time Settlement Interval 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 each of the preceding three Real-time Settlement Intervals of the 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 Real-time Settlement Interval in order to provide Regulation and the resource's expected output in each of the preceding three Real-time Settlement Intervals of the shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in each of the preceding three Real-time Settlement Intervals of the 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 Real-time Settlement Interval) in the PJM Interchange Energy Market, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during each of the following three Real-time Settlement Intervals of the 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 Real-time Settlement Interval in order to provide Regulation and the resource's expected output in each of the following three Real-time Settlement Intervals of the shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in each of the following three Real-time Settlement Intervals of the 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 all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Market Participant in a Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

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

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

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

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

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

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

(j) The Office of the Interconnection shall calculate a unit-specific benefits factor for each of the dynamic Regulation signal and traditional Regulation signal in accordance with the PJM Manuals. Each resource shall be assigned a unit-specific benefits factor based on their

order in the merit order stack for the applicable Regulation signal. The unit-specific benefits factor is the point on the benefits factor curve that aligns with the last megawatt, adjusted by historical performance, that resource will add to the dynamic resource stack. Resources following the dynamic Regulation signal which have a unit-specific benefits factor less than 0.1 will not be considered for the purposes of committing resources. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

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

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

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

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

where δ is delay.

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

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

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

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

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

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

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

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

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

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

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

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

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region multiplied by the historic accuracy score of the resource and multiplied by the unit-specific benefits factor for which the capability cost-based offer plus the performance cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The three-pivotal supplier test will apply on a Regulation supplier basis (i.e. not a resource by resource basis) and only the Regulation suppliers that fail the three-pivotal supplier test will have their Regulation offers capped. A Regulation supplier for the purposes of this section includes corporate affiliates. Regulation from resources controlled by a Regulation supplier or its affiliates, whether by contract with unaffiliated third parties or otherwise, will be included as Regulation of that Regulation supplier. Regulation provided by resources owned by a Regulation supplier but controlled by an unaffiliated third party, whether by contract or otherwise, will be included as Regulation of that third party.

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

a third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the applicable offer for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that 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. PJMSettlement shall be the Counterparty to the purchases and sales of Operating Reserve in the PJM Interchange Energy Market.

(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 Costs and No-load Costs and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. PJM shall also (i) determine whether any resources were scheduled in the Day-ahead Energy Market to provide Black Start service, Reactive Services or transfer interface control during the Operating Day because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day in order to minimize the total cost of Operating Reserves associated with the provision of such services and reflect the most accurate possible expectation of real-time operating conditions in the day-ahead model, which resources would not have otherwise been committed in the day-ahead security-constrained dispatch and (ii) report on the day following the Operating Day the megawatt quantities scheduled in the Day-ahead Energy Market for the above-enumerated purposes for the entire RTO.

Except as provided in Section 3.2.3(n), if the total offered price for Start-up Costs (shutdown costs for Demand Resources) and No-load Costs and energy summed over all Day-ahead Settlement Intervals exceeds the total value summed over all Day-ahead Settlement Intervals, the difference shall be credited to the Market Seller as a day-ahead Operating Reserve credit.

However, for the Day-ahead Settlement Intervals in which the resource is scheduled to provide energy in the Operating Day and the resource actually provides energy in at least one Real-time Settlement Interval in an hour that corresponds to such scheduled Day-ahead Settlement Intervals, a resource's day-ahead Operating Reserve credit shall be reduced by the greater of zero or the difference of the resource's Day-ahead Operating Reserve Target and the Balancing Operating Reserve Target, as determined below.

A resource's Day-ahead Operating Reserve Target shall be determined in accordance with the following equation:

$$(A + B) - C$$

Where:

A = Start-up Costs

B = the sum of day-ahead No-load Costs and energy over the applicable Real-time Settlement Intervals that correspond with Day-ahead Settlement Intervals in which the resource is scheduled. The day-ahead No-load Costs and energy are divided by twelve to determine the cost for each Real-time Settlement Interval.

C = the sum of the day-ahead revenues calculated for each Real-time Settlement Interval that corresponds with a Day-ahead Settlement Interval in which the resource is scheduled, where the day-ahead revenue for each such Real-time Settlement Interval equals the product of the megawatt amount of energy scheduled in the Day-ahead Energy Market and the Day-ahead Price at the applicable pricing point for the resource divided by twelve.

A resource's Balancing Operating Reserve Target shall be determined in accordance with the following equation:

$$D - (E + F)$$

Where:

D = the sum of Start-up Costs and No-load Costs and the incremental cost of energy summed over all Real-time Settlement Intervals that correspond to the Day-ahead Settlement Intervals in which the resource was scheduled;

E = [(the megawatt amount of energy provided in the Real-time Energy Market minus the megawatt amount of energy scheduled in the Day-ahead Energy Market) multiplied by the Real-time Price at the applicable pricing point for the resource] plus the sum of the day-ahead revenues as determined in part C of the above formula for determining the Day-ahead Operating Reserve Target, summed over the applicable Real-time Settlement Intervals; and

F = the sum of all revenues earned for providing Day-ahead Scheduling Reserves, Synchronized Reserves, Non-Synchronized Reserves, and Reactive Services over the applicable Real-time Settlement Intervals.

The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this section 3.2.3(b) to real-time deviations or real-time load share plus exports, pursuant to Operating Agreement, Schedule 1, section 3.2.3(p), 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.

(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), accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day and accepted Up-to Congestion Transactions in the Day-ahead Energy Market in megawatt-hours for the Operating Day at the sink of the transaction; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside such area pursuant to Section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load (net of operating Behind The Meter Generation) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following Segments: 1) the greater of their day-ahead schedules and minimum run time specified at the time of commitment (minimum

down time specified at the time of commitment for Demand Resources); and 2) any block of Real-time Settlement Intervals the resource operates at PJM's direction in excess of the greater of its day-ahead schedule and minimum run time specified at the time of commitment (minimum down time specified at the time of commitment for 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 specified at the time of commitment (minimum down time specified at the time of commitment for Demand Resources) and Segment 2 will include the remainder of the contiguous Real-time Settlement Intervals when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

A Generation Capacity Resource that operates outside of its unit-specific parameters will not receive Operating Reserve Credits nor be made whole for such operation when not dispatched by the Office of the Interconnection, unless the Market Seller of the Generation Capacity Resource can justify to the Office of the Interconnection that operation outside of such unit-specific parameters was the result of an actual constraint. Such Market Seller shall provide to the Market Monitoring Unit and the Office of the Interconnection its request to receive Operating Reserve Credits and/or to be made whole for such operation, along with documentation explaining in detail the reasons for operating its resource outside of its unit-specific parameters, within thirty calendar days following the issuance of billing statement for the Operating Day. The Market Seller shall also respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection. The Market Monitoring Unit shall evaluate such request for compensation and provide its determination of whether there was an exercise of market power to the Office of the Interconnection by no later than twenty-five calendar days after receiving the Market Seller's request for compensation. The Office of the Interconnection shall make its determination whether the Market Seller justified that it is entitled to receive Operating Reserve Credits and/or be made whole for such operation of its resource for the day(s) in question, by no later than thirty calendar days after receiving the Market Seller's request for compensation.

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 Tariff, Attachment K-Appendix, section 3.2.3(f) and the parallel provision of Operating Agreement, Schedule 1, section 3.2.3(f); or 2) the resource submits a request for a risk premium to the Market Monitoring Unit under the procedures specified in Tariff, Attachment M – Appendix, section II.B. A nuclear generation resource (i) must submit a risk premium consistent with its agreement under such process, or, (ii) if it has not agreed with the Market Monitoring Unit on an appropriate risk premium, may submit its own determination of an appropriate risk premium to the Office of the Interconnection, subject to acceptance by the Office of the Interconnection, with or without prior approval from the Commission.

Credits received pursuant to this section shall be equal to the positive difference between a resource's Total Operating Reserve Offer, and the total value of the resource's energy in the

Day-ahead Energy Market plus any credit or change for quantity deviations, at PJM dispatch direction (excluding quantity deviations caused by an increase in the Market Seller's Real-time Offer), from the Day-ahead Energy Market during the Operating Day at the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for Segment 2 shall exclude start up (shutdown costs for Demand Resources) costs for generation resources.

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

Synchronized Reserve, Non-Synchronized Reserve, and Real-time Settlement Interval share of the 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 Real-time Settlement Interval(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 Real-time Settlement Interval the unit operates in condensing and generation mode.

(f) A Market Seller of a unit not defined in subsection (f-1), (f-2), or (f-4) hereof (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than \$0.00. This equation is represented as $(A*B) - C$.

(f-1) With the exception of Market Sellers of Flexible Resources that submit a Real-time Offer greater than their resource's Committed Offer in the Day-ahead Energy Market, a Market Seller of a Flexible Resource shall be compensated for lost opportunity cost, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if either of the following conditions occur:

- (i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described in section 3.2.3 (f).
- (ii) If the unit is scheduled to produce energy in the Day-ahead Energy Market for a Day-ahead Settlement Interval, but the unit is not called on by the Office of the Interconnection and does not operate in the corresponding Real-time Settlement Interval(s), then the Market Seller shall be credited in an amount equal to the higher of:
 - 1) the product of (A) the amount of megawatts committed in the Day-ahead Energy Market for the generating unit, and (B) the Real-time Price at the generation bus for the generating unit, minus the sum of (C) the Total Lost Opportunity Cost Offer plus No-load Costs, plus (D) the Start-up Cost, divided by the Real-time Settlement Intervals committed for each set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market. This equation is represented as $(A*B) - (C+D)$. The startup cost, (D), shall be excluded from this calculation if the unit operates in real time following the Office of the Interconnection's direction during any portion of the set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market, or
 - 2) the Real-time Price at the unit's bus minus the Day-ahead Price at the unit's bus, multiplied by the number of megawatts committed in the Day-ahead Energy Market for the generating unit.

Market Sellers of Flexible Resources that submit a Real-time Offer greater than their resource's Committed Offer in the Day-ahead Energy Market shall not be eligible to receive compensation for lost opportunity costs under any applicable provisions of Schedule 1 of this Agreement.

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

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output

due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-4) A Market Seller of a wind generating unit that is pool-scheduled or self-scheduled, has SCADA capability to transmit and receive instructions from the Office of the Interconnection, has provided data and established processes to follow PJM basepoints pursuant to the requirements for wind generating units as further detailed in this Agreement, the Tariff and the PJM Manuals, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the , real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than \$0.00. This equation is represented as $(A*B) - C$.

(f-5) (i) A Market Seller of a pool-scheduled resource or a dispatchable self-scheduled resource shall receive Dispatch Differential Lost Opportunity Cost credits as calculated under subsection (iv) below if the resource is dispatched to provide energy in the Real-time Energy Market, provided such resource is not committed to provide real-time ancillary services (Regulation, reserves, reactive service) or instructed to reduce or suspend output due to a transmission constraint or other reliability issue pursuant to Operating Agreement, Schedule 1, section 3.2.3(f-1) through Operating Agreement, Schedule 1, section (f-4).

(ii) PJM will calculate the revenue above cost for the pricing run for each Real-time Settlement Interval in accordance with the following equation:

$$(A \times B) - C$$

Where:

A = the resource's expected output level based on its resource parameters at the Real-time Price at the applicable pricing point;

B = the Real-time Price at the applicable pricing point; and

C = the sum of the resource's Real-time Energy Market offer integrated under the Final Offer for the resource's expected output level based on its resource parameters at the Real-time Price at the applicable pricing point.

(iii) PJM will calculate the revenue above cost for the dispatch run for each Real-time Settlement Interval in accordance with the following equation:

$$(\text{greater of A and B}) - (\text{lesser of C and D})$$

Where:

A = the product of the amount of megawatts of energy dispatched in the Real-time Energy Market dispatch run for the resource in that Real-time Settlement Interval and the Real-time Price at the applicable pricing point;

B = the product of the amount of megawatts of energy the resource actually provided in that Real-time Settlement Interval and the Real-time Price at the applicable pricing point;

C = the resource's Real-time Energy Market offer integrated under the Final Offer for the amount of megawatts dispatched in the Real-time Energy Market dispatch run;

D = the resource's Real-time Energy Market offer integrated under the Final Offer for the amount of megawatts the resource actually provided in that Real-time Settlement Interval.

(iv) The Dispatch Differential Lost Opportunity Cost credit shall equal the greater of (A) the difference between the revenue above cost based on the pricing run determined in subsection (f-5)(ii) and the revenue above cost based on the dispatch run determined in subsection (f-5)(iii) or (B) zero.

(v) For each hour in an Operating Day, the total cost of the Dispatch Differential Lost Opportunity Cost credits shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load ((a) net of operating Behind The Meter Generation, but not to be less than zero; and (b) excluding Direct Charging Energy) in the PJM Region, served under Network Transmission Service, in megawatt-hours; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Operating Agreement, Schedule 1, section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(g) The sum of the foregoing credits in Operating Agreement, Schedule 1, section 3.2.3(f-1) through Operating Agreement, Schedule 1, section 3.2.3(f-4), 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 shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, shall be allocated and charged to each Market Participant based on their daily total of hourly deviations determined in accordance with the following equation:

$$\sum_h (A + B + C)$$

Where:

h = the hours in the applicable Operating Day;

A = For each Real-time Settlement Interval in an hour, the sum of the absolute value of the withdrawal deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy withdrawals (net of operating Behind The Meter Generation) in the Real-Time Energy Market, except as noted in subsection (h)(ii) below and in the PJM Manuals divided by the number of Real-time Settlement Intervals for that hour. The summation of each Real-time Settlement Interval's withdrawal deviation in an hour will be the Market Participant's total hourly withdrawal deviations. Market Participant bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to section 1.12 of this Schedule are not included in the determination of withdrawal deviations;

B = For each Real-time Settlement Interval in an hour, the sum of the absolute value of generation deviations (in MW and not including deviations in Behind The Meter Generation) as determined in subsection (o) divided by the number of Real-Time Settlement Intervals for that hour;

C = For each Real-time Settlement Interval in an hour, the sum of the absolute value of the injection deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy injections in the Real-Time Energy Market divided by the number of Real-time Settlement Intervals for that hour. The summation of the injection deviations for each Real-time Settlement Interval in an hour will be the Market Participant's total hourly injection deviations. The determination of injection deviations does not include generation resources.

The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with section 3.1A of this Schedule shall be used in determining the real-time withdrawal deviations, generation deviations and injection deviations used to calculate Operating Reserve under this subsection (e).

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

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

Deviations that occur within a single Zone shall be associated with the Eastern or Western Region, as defined in Section 3.2.3(q) of this Schedule, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with Section 3.2.3(q). Deviations at a hub shall be associated with the Eastern or Western Region if all the buses that define the hub are located in the region. Deviations at an Interface Pricing Point shall be associated with whichever region, the Eastern or Western Region, with which the majority of the buses that define that Interface Pricing Point are most closely electrically associated. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by buses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed for each Real-time Settlement Interval in accordance with the following provisions:

- (i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.
- (ii) Demand deviations will be assessed by comparing all day-ahead demand transactions, which include the components referenced in section 3.2.3(d) regarding the cost of Operating Reserves in the Day-ahead Energy Market, at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage.
- (iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface.
- (iv) Bilateral transactions inside the PJM Region, as defined in Operating Agreement, Schedule 1, section 1.7.10, will not be included in the determination of Supply or Demand deviations.

(i) At the end of each Operating Day, Market Sellers shall be credited 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 Dynamic Transfers 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 and greater than the Market Seller’s lowest

available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. 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 Real-time Settlement Intervals that the offer is economic divided by the megawatt hours of energy provided during the Real-time Settlement Intervals that the offer is economic. The Real-time Settlement Intervals that the offer is economic shall be: (i) the Real-time Settlement Intervals that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the Real-time Settlement Intervals in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any Real-time Settlement Intervals required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price for a market-based offer is greater than \$1,000/MWh and greater than the Market Seller's lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 11:00 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than \$1,000/MWh, the Market Seller shall receive credit for 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 below and in the PJM Manuals.

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

- (i) real-time economic minimum \leq 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.
- (ii) real-time economic maximum \geq 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

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

$$Ramp_Request_t = \frac{(Dispatchtarget_{t-1} - AOutput_{t-1})}{(LAtime_{t-1})}$$

$$RL_Desired_t = AOutput_{t-1} + (Ramp_Request_t * Case_Eff_time_{t-1})$$

where:

1. Dispatchtarget = Dispatch Signal for the previous approved Dispatch case
2. AOutput = Unit's achievable target MW at case solution time as defined in the PJM Manuals
3. LAtime = Dispatch look ahead time
4. Case_Eff_time = Time between signal changes
5. RL_Desired = Ramp-limited desired MW

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

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and dispatch signal, or if its %

off dispatch is ≤ 10 , or its Real-time Settlement Interval MWh is within 5% of the Real-time Settlement Interval ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined for each Real-time Settlement Interval in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – Day-Ahead MWh.
- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – dispatch LMP Desired MW.
- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time Settlement Interval MWh – Ramp-Limited Desired MW.
- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and dispatch LMP Desired MWh for the Real-time Settlement Interval is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: Real time Settlement Interval MWh – dispatch LMP Desired MWh.
- If a resource is not following dispatch and its % Off Dispatch is $\leq 20\%$, balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh – Ramp-Limited Desired MW. If deviation value is within 5% of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.
- If a resource is not following dispatch and its % off Dispatch is $> 20\%$, balancing Operating Reserve deviations shall be assessed according to the following formula: Real time Settlement Interval MWh – dispatch LMP Desired MWh.
- If a resource is not following dispatch, and the resource has tripped, for the Real-time Settlement Interval the resource tripped and the Real-time Settlement Intervals it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: Real time Settlement Interval MWh – Day-Ahead MWh.
- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time Settlement Interval MWh - Day-Ahead MWh.

If a resource has a sum of the absolute value of generator deviations for an hour that is less than 5 MWh, then the resource shall not be assessed balancing Operating Reserve deviations for that hour.

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

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

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

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

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

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

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

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

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

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

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

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

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total

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

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

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

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

(r) Market Sellers that incur incremental operating costs for a generation resource that are either greater than \$1,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Schedule 2 of the Operating Agreement and PJM Manual 15, but are not verified at the time of dispatch of the resource under section 6.4.3 of this Schedule, or greater than \$2,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Schedule 2 of the Operating Agreement, and PJM Manual 15, will be eligible to receive credit for Operating Reserves upon review of the Market Monitoring Unit and the Office of the Interconnection, and approval of the Office of the Interconnection. Market Sellers must submit to the Office of the Interconnection and the Market Monitoring Unit all relevant documentation demonstrating the calculation of costs greater than \$2,000/MWh, and costs greater than \$1,000/MWh which were not verified at the time of dispatch of the resource under section 6.4.3 of this Schedule. The Office of the Interconnection must approve any Operating Reserve credits paid to a Market Seller under this subsection (r).

3.2.3A Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter

Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour (“Synchronized Reserve Obligation”), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b).

Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant with an hourly Synchronized Reserve Obligation shall be charged the pro rata share of the sum of the quantity of Synchronized Reserves provided in each Real-time Settlement Interval times the clearing price for all Real-time Settlement Intervals in the hour associated with that obligation.

(b) A resource 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, as described in 3.2.3A (c), with the exception of those Real-time Settlement Intervals in which the Non-Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone is not equal to zero. During such hours, Tier 1 Synchronized Reserve resources shall be compensated at the Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone for the lesser of the 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 in a Real-time Settlement Interval.

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 to a Synchronized Reserve Event in a Real-time Settlement Interval 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 in a Real-time Settlement Interval 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 an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval of the Operating Day. The hourly Synchronized Reserve Market Clearing Price shall be calculated as the 5-minute clearing price. Each 5-minute clearing price shall be calculated as the marginal cost of serving the next increment of demand for Synchronized Reserve in each Reserve Zone or Reserve Sub-zone, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve Requirement or Extended Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met in the pricing run, the 5-minute clearing price shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the sum of the Reserve Penalty Factors for the Synchronized Reserve Requirement and Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the 5-minute clearing price shall be the sum of the Reserve Penalty Factors for the Primary Reserve Requirement and the Synchronized Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

The Reserve Penalty Factor for the Synchronized Reserve Requirement shall be \$850/MWh.

The Reserve Penalty Factor for the Extended Synchronized Reserve Requirement shall be \$300/MWh.

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

(e) For each Real-time Settlement Interval and for determining the 5-minute Synchronized Reserve clearing price, the estimated unit-specific opportunity cost for a generation resource will be determined in accordance with the following equation:

$$(A \times B) + (C \times D)$$

Where

A = The Locational Marginal Price at the generation bus for the generation resource;

B = The megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer;

C = 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; and

D = The difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a resource 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 Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be in accordance with the following equation:

$$(A \times B) + (C \times D)$$

Where:

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;

B = The Locational Marginal Price at the generation bus of the generation resource;

C = 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; and

D = 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 Participant in excess of that Market Participant's Synchronized Reserve Obligation, the Tier 1 Synchronized Reserve that is not utilized to fulfill the Market Participant's obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

(h) Any amounts credited for Tier 2 Synchronized Reserve in a Real-time Settlement Interval in excess of the Synchronized Reserve Market Clearing Price in that Real-time Settlement Interval shall be allocated and charged to each Market Participant 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 a Real-time Settlement Interval than was estimated as needed at the time the Synchronized Reserve Market Clearing Price was calculated for that Real-time Settlement Interval 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) A generation resource or Demand Resource will be credited for the assigned and/or self-scheduled amount of Tier 2 Synchronized Reserve, less any applicable Tier 2 Synchronized Reserve shortfall, multiplied by the Synchronized Reserve Market Clearing Price for each Real-Time Settlement Interval, in which they were assigned and/or self-scheduled. In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled to provide Tier 2 Synchronized Reserve fails to provide the PJM calculated expected response of Tier 2 Synchronized Reserve in response to a Synchronized Reserve Event, the generation resource or Demand Resource will have a Tier 2 Synchronized Reserve shortfall. The Tier 2 Synchronized Reserve shortfall amount will be the difference between the lesser of the assigned plus self-scheduled amount or the PJM-calculated expected response and the actual response provided. The PJM-calculated expected response is based on the energy dispatch signals and instructions of the Office of the Interconnection. The Tier 2 Synchronized Reserve shortfall amount is for all Real-time Settlement Intervals the generation resource or Demand Resource was assigned and/or self-scheduled Tier 2 Synchronized Reserve on the Operating Day during which the event occurred. The determination of the amount of Synchronized Reserve credited to a generation resource or Demand Resource shall be on an individual resource basis, not on an aggregate basis.

The resource shall refund payments received for Tier 2 Synchronized Reserve it failed to provide. For purposes of determining the amount of the payments to be refunded by a Market Participant, the Office of the Interconnection shall calculate the shortfall of Tier 2 Synchronized Reserve on an individual resource basis unless the Market Participant had multiple Demand Resources that were assigned or self-scheduled to provide Tier 2 Synchronized Reserve, in which case the shortfall will be determined on an aggregate basis. For performance determined on an aggregate basis, the response of any Demand Resource that provided more Tier 2 Synchronized Reserve than it was assigned or self-scheduled to provide will be used to offset the performance of other Demand Resources that provided less Tier 2 Synchronized Reserve than they were assigned or self-scheduled to provide during a Synchronized Reserve Event, as calculated in the PJM Manuals. The determination of a Market Participant's aggregate response

shall not be taken into consideration in the determination of the amount of Tier 2 Synchronized Reserve credited to each individual Demand Resource.

The amount refunded shall be determined by multiplying the Synchronized Reserve Market Clearing Price by the amount of the shortfall of Tier 2 Synchronized Reserve, measured in megawatts, for all intervals the resource was assigned or self-scheduled to provide Tier 2 Synchronized Reserve for a period of time immediately preceding the Synchronized Reserve Event equal to the lesser of the average number of days between Synchronized Reserve Events, or the number of days since the resource last failed to provide the amount of Tier 2 Synchronized Reserve it was assigned or self-scheduled to provide in response to a Synchronized Reserve Event. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following January 1. The refunded charges shall be allocated as credits to Market Participants based on its pro rata share of the Synchronized Reserve Obligation megawatts less any Tier 1 Synchronized Reserve applied to its Synchronized Reserve Obligation in the hour(s) of the Synchronized Reserve Event for the Reserve Sub-zone or Reserve Zone, except that Market Participants that incur a refund obligation and also have an applicable Synchronized Reserve Obligation during the hour(s) of the Synchronized Reserve Event shall not be included in the allocation of such refund credits. If the event spans multiple hours, the refund credits will be prorated hourly based on the duration of the event within each clock hour.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or 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 or increased by the amount the megawatt output of the generation resource differs from 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 but will be capped. If the generation resource has an assignment and the PJM-calculated expected response is greater than the assigned, then the megawatt output will be capped at the difference of the PJM-calculated expected response and the assigned. If the generation resource has no assignment, then the megawatt output will be capped at the PJM-calculated expected response. The PJM-calculated expected response is based on the energy dispatch signals and instructions of the Office of the Interconnection. 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 Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market Participant's total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant with an hourly Non-Synchronized Reserve Obligation shall be charged the pro rata share of the sum of the quantity of Non-Synchronized Reserves provided in each Real-time Settlement Interval times the clearing price for all Real-time Settlement Intervals in the hour associated with that obligation.

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

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection in the Real-time Price software program, which is known as the pricing run, for each Real-time Settlement Interval of the Operating Day. The Non-Synchronized Reserve Market Clearing Price shall be calculated as the 5-minute clearing price. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve Requirement or Extended Primary Reserve Requirement. When the Primary Reserve Requirement or Extended Primary Reserve Requirement in a Reserve Zone

or Reserve Sub-zone cannot be met in the pricing run at a price less than or equal to the applicable Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the 5-minute clearing price shall be the Reserve Penalty Factor for the Primary Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

The Reserve Penalty Factor for the Synchronized Reserve Requirement shall be \$850/MWh.

The Reserve Penalty Factor for the Extended Primary Reserve Requirement shall be \$300/MWh.

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

(d) For each Real-time Settlement Interval and for determining the 5-minute Non-Synchronized Reserve clearing price, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves will be determined in accordance with the following equation:

$$(A \times B) - C$$

Where:

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;

B = The Locational Marginal Price at the generation bus for the generation resource; and

C = The applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a resource 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 Real-time Settlement Interval that the Office of the Interconnection requires a generation resource to provide Non-Synchronized Reserve and shall be in accordance with the following equation:

$$(A \times B) - C$$

Where:

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;

B = The Locational Marginal Price at the generation bus for the generation resource; and

C = The applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

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

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

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

3.2.3A.01 Day-ahead Scheduling Reserves.

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

bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

(b) A Day-ahead Scheduling Reserves Resource that receives a Day-ahead Scheduling Reserves schedule pursuant to subsection (a) of this section shall be paid the hourly Day-ahead Scheduling Reserves Market clearing price, as determined in the day-ahead pricing run set forth in Operating Agreement, Schedule 1, section 2.6, for the cleared megawatt quantity of Day-ahead Scheduling Reserves 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 hourly credits paid to Day-ahead Scheduling Reserves Resources satisfying the Base Day-ahead Scheduling Reserves Requirement (“Base Day-ahead Scheduling Reserves credits”) shall equal the ratio of the Base Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement, multiplied by the total credits paid to Day-ahead Scheduling Reserves Resources, and are allocated as Base Day-ahead Scheduling Reserves charges per paragraph (i) below. The hourly credits paid to Day-ahead Scheduling Reserve Resources satisfying the Additional Day-ahead Scheduling Reserve Requirement (“Additional Day-ahead Scheduling Reserves credits”) shall equal the ratio of the Additional Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement, multiplied by the total credits paid to Day-ahead Scheduling Reserves Resources and are allocated as Additional Day-ahead Scheduling Reserves charges per paragraph (ii) below.

- (i) A Market Participant’s Base Day-ahead Scheduling Reserves charge is equal to the ratio of the Market Participant’s hourly obligation to the total hourly obligation of all Market Participants in the PJM Region, multiplied by the Base Day-ahead Scheduling Reserves credits. The hourly obligation for each Market Participant is a megawatt representation of the portion of the Base Day-ahead Scheduling Reserves credits that the Market Participant is responsible for paying to PJM. The hourly obligation is equal to the Market Participant’s load ratio share of the total megawatt volume of Base Day-ahead Scheduling Reserves resources (described below), based on the Market Participant’s total hourly load (net of operating Behind The Meter Generation, but not to be less than zero) to the total hourly load of all Market Participants in the PJM Region. The total megawatt volume of Base Day-ahead Scheduling Reserves resources equals the ratio of the Base Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement multiplied by the total volume of Day-ahead Scheduling Reserves megawatts paid pursuant to paragraph (c) of this section. A Market Participant’s hourly Day-ahead Scheduling Reserves obligation can be further adjusted by any Day-ahead Scheduling Reserve bilateral transactions.
- (ii) Additional Day-ahead Scheduling Reserves credits shall be charged hourly to Market Participants that are net purchasers in the Day-ahead Energy Market based on its positive demand difference ratio share. The positive demand difference for each Market Participant is the difference between its real-time load (net of operating Behind The Meter Generation, but not to be less than zero) and cleared Demand Bids in the Day-ahead Energy Market, net of cleared Increment Offers and cleared Decrement Bids in the Day-ahead Energy Market, when such value is positive. Net purchasers in the Day-ahead Energy Market are those Market

Participants that have cleared Demand Bids plus cleared Decrement Bids in excess of its amount of cleared Increment Offers in the Day-ahead Energy Market. If there are no Market Participants with a positive demand difference, the Additional Day-ahead Scheduling Reserves credits are allocated according to paragraph (i) above.

(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 real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit for each Real-time Settlement Interval in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than \$0.00. This equation is represented as $(A*B) - C$.

(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 for each Real-time Settlement Interval, limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the

Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(e) At the end of each Operating Day, where the active energy output 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 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 in an amount equal to $\{(AG - LMPDMW) \times (UB - URTLMP)\}$ where:

AG equals the actual 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 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 lesser of the Final Offer or Committed Offer;

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

where $UB - URTLMP$ shall not be negative.

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

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a

mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market Participant 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 Synchronized Reserve Market Clearing Price for each Real-time Settlement Interval a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generating unit's bus, (C) the generating unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generating resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generating unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of the Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

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

whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

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

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

3.2.3C Synchronous Condensing for Post-Contingency Operation.

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

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve.

At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Synchronized Reserve Market Clearing Price for each applicable interval a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's applicable interval cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the applicable interval 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 for the Synchronized Reserve Requirement and Primary Reserve Requirement, provided that the Emergency energy is needed to meet demand in the PJM Region.
- (b) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each applicable interval of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.
- (c) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each applicable interval of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.
- (d) The net costs or net revenues associated with sales or purchases of energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each applicable interval of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net withdrawals and injections in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

- (a) PJMSettlement shall prepare a billing statement each billing cycle for each Market Participant in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market Participant's internal accounting.
- (b) If deliveries to a Market Participant that has PJM Interchange meters in accordance with 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 Participant, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market

Participant and the unmetered Market Participant specified by them to the Office of the Interconnection.